Proceedings
of
SYMPOSIUM ON COMPUTER ANALYSIS OF ELECTRIC LOAD FORECASTING AND GENERATING CAPACITY EXPANSION

September 14-16, 1983
Columbus, Ohio, USA

Edited by

S. Nakamura

Printed and Published by

The National Regulatory Research Institute
2130 Neil Avenue
Columbus, Ohio 43210

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FORECASTING MODELS: AN EVOLUTION IN DISGUISE

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Introduction

Almost before our very eyes, forecasting of energy services has entered a new era. No longer are the composite needs of utility customers adequately represented by forecasts of peak demand and total energy use. Two specific developments have changed this. First is the economic necessity for greater accuracy in forecasting, and second is the emerging potential of demand-side planning. The latter is the concept by which utilities define strategic institutional objectives in terms of their involvement in demand-side activities, ranging from conservation and load management to electrification.

Addressing these two issues of more accurate forecasts and demand-side planning requires a level of detail in prediction unimagined only a few years ago. Hour-by-hour load shape forecasts are now necessary. Furthermore, the end-use components of the load shape must be known in order to exercise planning options and to determine, say, the extent of a conservation program involving insulation financing or the most desirable rate of penetration of a load management program involving control of water heaters. The author will discuss this evolution and the types of models available today.

Such requirements have caused a virtual explosion of information needs. These needs include greatly expanded load and consumer research activities within utilities, as well as an increased need for utilities to reach out and exchange methods, information, and data. The expanded information needed to improve forecasting accuracy and load shape forecasting for demand-side planning requires the use of computers capable of manipulating large load-forecasting models. Some have criticized the industry for its continued and semmingly blind reliance on computer-generated forecasts. They seem to have missed the point. Forecasting remains an art only to the extent that the science is not fully defined. Computers are a most necessary and helpful tool to enhance the scientific aspects of forecasting and to mitigate the uncertainties inherent in it. Their use serves to support the artistry of judgment.

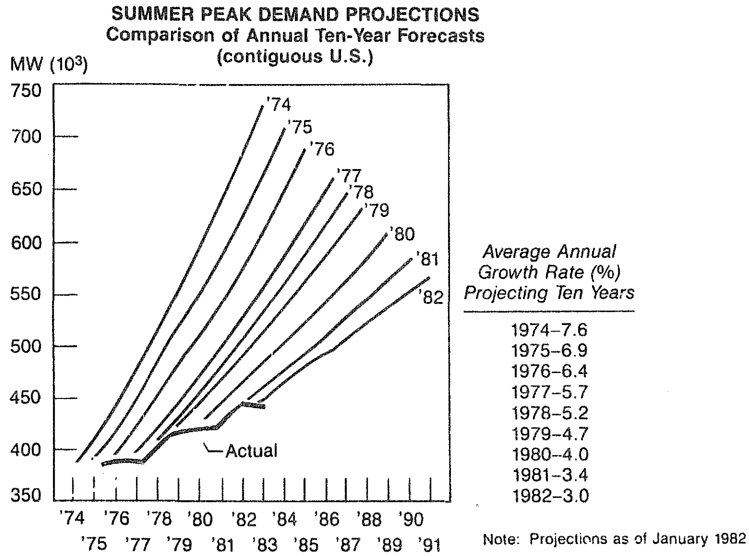
Straight-line extrapolations and simple regression analysis of historical energy consumption trends that had served well enough for the years of steady prices and steady growth became inadequate for many purposes with the onset of inflation during the late 1960s. Nor could these simple techniques cope with variations in growth rates among the different energy-consuming sectors of the economy.

Fortunately, some within the utility industry had anticipated the need for more sophisticated forecasting methods and were already at work on approaches that, for example, looked at demand and sales versus energy prices. Explicit recognition that the demand for energy was also dependent on other factors, such as income, weather, and the economy, lay behind the serious efforts that began in the late 1960s to model those relationships as a basis for forecasting. Modeling efforts accelerated when the Arab oil embargo of the early 1970s brought a sharp break in historical patterns.

Clearly, knowing how much energy Americans had consumed in the past no longer offered a simple linear guide to knowing what they would consume in the future under drastically altered conditions of price and availability.

In addition, the need for greater accuracy in energy demand forecasting is evidenced by the annual reduction in the North American Electric Reliability Council's compilation of the 10-year forecasts of peak electric energy demand in the conterminous United States illustrated in Figure I. This departure from the historical trend has been caused by increased energy prices, a general slowdown in the economy, and a reduction in energy use.

Figure I



At the same time that forecasting grew more difficult, the consequences of forecast errors grew more serious. In the past, overestimates of future energy demand were quickly made right by demand growth, and the worst consequence was temporary excess capacity that was soon absorbed. Underestimates were not critical either, because turbine generators fired by cheap oil or gas could plug the gap while new baseload plants were coming on-line.

Today all this has changed. An overestimate can lead to the authorization of a baseload plant that may not be needed for several years, turning it into a financial burden for the utility that must bear the costs without offsetting revenues. An underestimate may be even worse, since it takes 8-10 years to license and build a coal-fired baseload plant and longer for a nuclear plant. Meanwhile, meeting its load may force a utility to use oil- or gas-fired turbines that are now expensive to operate and no longer easy to gain approval for, or to purchase similarly expensive power through pooling arrangements with other utilities. If a condition of undercapacity is allowed to exist, voltage reductions, localized brownouts, or even blackouts can occur.

The result is a bind for the utility planner. Squeezed between the dual threats of over and undercapacity, the planner needs accurate forecasts more than ever.

Modeling Activity

One popular method for end-use forecasting receiving a lot of attention is called the engineering approach, which uses so-called physically based end-use modeling. The focus is on the physical stock of energy-using equipment - for example, the projected number of electric dishwashers in American homes. Taking this number and multiplying it by a projected utilization rate yields a forecast of total electricity use by home dishwashers. This figure is then added to similarly derived figures for other major electrical appliances used in the home, from air conditioners to electric ranges, to arrive at an aggregated forecast of electricity use for the residential sector as a whole.

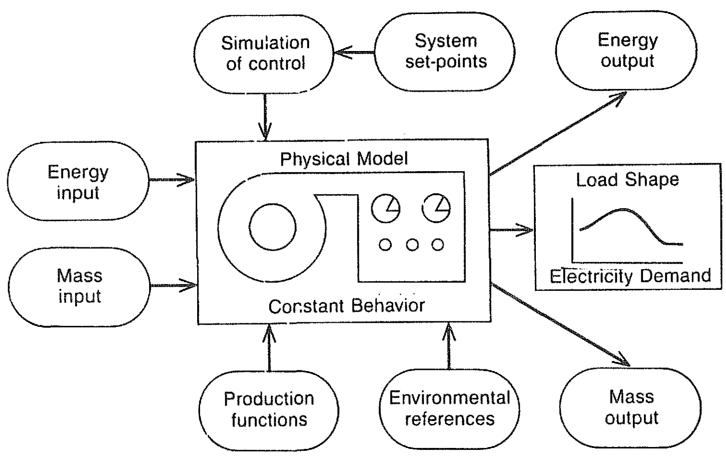
End-use engineering simulaton models are computer programs which began to crop-up in the 1960s as promotional tools of utilities. Two prime examples are the AXCESS program sponsored by the Edison Electric Institute and the E^3 program sponsored by the American Gas Association. Each of the programs allowed physical simulation of commercial building energy requirements concentrating on heating, cooling, water heating requirements and including cogeneration evaluation.

In the early 1970s the same methodology adopted a somewhat different appeal - conservation and load management had become a curiosity and evaluation of individual alternatives were adopted through use of these models. Now, in the 80s, they have become a valuable means to evaluate potential technological alterntives for individual case studies. One serious shortcoming exists in their use - they ignore consumer behavior.

Figure II illustrates the generic elements of an engineering simulation model. All energy related appliances, processes or systems (physical model) can be depicted in a mass-balance relationship. In this relationship varous levels of energy representing heat content or thermal energy, kientic/potential energy or mechanical energy and raw energy in the form of hydrocarbons are inputted to a system at some mass. Similarly, energy, mass and a demand for electric energy are on output of this simulation.

Figure II

ENGINEERING SIMULATION MODELS



The operation of the physical model is based on some simulation of control, or on/off and intensity parameters. The simulation also depends on production functions, or process models, which relate production to energy requirements and environmental references such as weather and time to performance.

As an example, if the simulation were for an airconditioning system used in space cooling, the elements illustrated in Figure II would be as follows:

1) Energy Input - reflects the thermal content of the air before it passes over the evaporator coil.

2) Mass Input - reflects the volume and density of air before it moves over the evaporator coil.

3) Simulation of Control - and system setpoints would reflect the thermostat setting, including on-off, temperature and time-of-day variations. The reaction of the thermostat in the physical model would depict occupancy, internal heat gain and external heat gain.

4) Production Functions - model the energy requirements of the system as a function of its thermal loading. The enthalpy of the air and its volume passing over the evaporating coil determines the input to the system. The ambient conditions surrounding the condensing coil are also a factor which reflect the ability of the system to reject heat.

5) Environmental References - include weather and time variations which determine heat gain over time.

6) Energy Output - reflects the thermal content of the air after it passes over the evaporator coil.

7) Mass Output - reflects the volume and density of air after it leaves the evaporator coil.

8) Load Shape - reflects the customer response or the demand for electric energy required by the system including the demand by the condensing fan, compressor, sump heater, defrost system, and evaporating fan.

9) Physical Model - would simulate the behavior of the system in trying to meet its set points.

A straightforward engineering approach that focuses only on physical factors can miss the emergence of new end uses and miss some other very important effects, such as the impact of rising energy prices as a stimulus to conservation.

Consequently, a major trend in energy forecasting is the effort to integrate into end-use models the behavioral element characteristic of what is known as the econometric approach. A behavioral or econometric model of electricity demand forecasts consumption in terms of consumer response to economic variables, such as price and income. In this type of simulation, it is assumed that all consumer behavior can be represented by an econometric model. A wide choice of variables can be included in such a model, from local employment levels to the gross national product.

Bringing together the physical factors and the behavioral factors in a single model allows a more comprehensive grasp of the many diverse influences that shape the demand for energy.

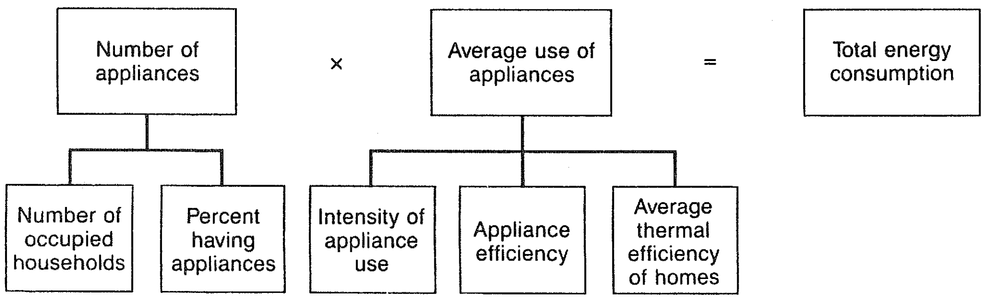
New Models

EPRI's Demand and Conservation Program has sponsored the development of one of the first hybrid econometric end-use models to be used for forecasting residential electricity demand. It is called REEPS, for residential end-use energy planning system.

Consistent with the end-use approach, REEPS itemizes the major household appliance activities, such as space heating and air conditioning. It predicts both consumer appliance choices and energy consumption resulting from the use of appliances. These appliance purchase and utilization decisions are related to price and income variables, and the exact structure of these relationships is estimated econometrically from individual household survey data. The aim is to capture the benefits of a forecast that is detailed down to the level of individual appliance use without ignoring the important economic factors that can be critical in shaping consumer behavior.

Figure III

RESIDENTIAL END-USE FORECASTING MODEL



One of the innovative features of REEPS is the method used to develop forecasts. Termed microsimulation, it involves simulating the behavior of a representative sample of households for the particular region under study. Each sample household is characterized by data on socioeconomic attributes (e.g., family size, income), number and type of appliances, size and type of dwelling, and the various geographic and economic features of the region.

Given this setting for decision making, the household makes its appliance investment choices. These choices will depend on the household characteristics already established, as well as on weather and energy prices. For example, a high-income family is more likely than a low-income family to purchase central air conditioning and living in a hot climate with relatively low electricity prices will reinforce this choice.

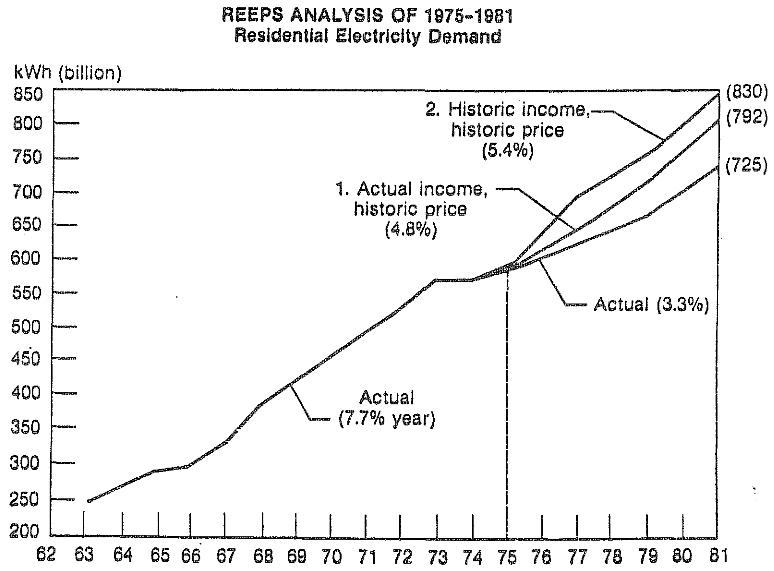
The next step is to predict how much energy a household will use, given its appliance stock. This amount will be the product of two distinct but closely related decisions. The household first selects the appliance's operating efficiency as part of the initial purchase decision. After the unit is installed, modifying its efficiency may be difficult or impossible. But household members can still decide how intensively to use the appliance, a decision shaped by socioeconomic and geographic features of the household, as well as by the operating costs of the appliance itself. When the efficiency and utilization decisions are combined, the result is the amount of energy that the appliance will consume.

Total consumption is forecast by multiplying the individual household predictions by the relative frequency with which each household type occurs in the population and adding the results. This composite picture of the full spectrum of consuming households offers a far more richly detailed view of energy consumption patterns than a forecast based simply on the homogenized average household (as is the case in simple engineering approaches).

Because of this structural detail, REEPS is a powerful tool for examining not only the total impact of increased prices or utility conservation programs but also the impact on specific segments of the population. The model can estimate not only how much energy is being consumed but who is consuming it and for what purpose. Further, because the model combines the advantages of the end-use and econometric approaches, it can assess both mandatory conservation effects, such as those that are built into the efficient new appliances, and the more elusive effects of conservation incentives, such as federal tax breaks, that rely heavily on consumer choice.

Figure IV presents an analysis of residential electricity demand during 1975-81 using the REEPS model. This model combines econometric techniques with end-use detail to develop a structurally detailed representation of residential electricity use drawing upon observed customer behavior and engineering data. REEPS was used to answer two questions: (1) what would residential demand have been if electricity prices and personal income had grown over 1975-81 at historic rates and (2) what demand would have been if income grew at the actual 1975-81 are but prices grew at historic rates.

Figure IV



The answer to the first question is that demand would have grown at an annual rate of 5.4% versus the actual rate of 3.3%. The answer to the second question indicates that if incomes had grown at the actual rate, demand growth would have been lower, 4.8%. The implication of these variations in growth rates is that in 1981 consumption would have been 830 billion kWh if both incomes and prices had grown at historic rates, or 14% higher than the actual 725 billion kWh. In aggregate terms, the reduction in sales of 105 billion corresponds to a reduction in needed capacity of approximately 20,000 MW. Of this reduction in demand growth, about 2/3rd can be attributed to higher prices and the remaining 1/3rd to lower incomes.

This illustrates total conservation which includes those actions stimulated by utility intervention. Many of the papers at this Conference address the extent to which utility conservation programs have encouraged these actions.

Transferability of analyses and data from one utility service area to another is being explored. For example, current work with time-of-day electricity pricing is examining how consumer response to these rates varies across different areas of the country. If responsiveness turns out to be about the same everywhere, or if the amount by which it is different depends on certain measurable variables, the results of a study in one service area can be applied (with adjustments if necessary) to planning decisions in another. This can save utilities considerable effort and expense. Two other projects already under way deal with transfer of data among utilities.

Time-of-day rate studies provide input to models that can forecast hourly load shapes, and a model for forecasting hourly loads system-wide over the long-term is now nearing completion. Traditional practice has been to forecast annual sales and peak loads separtately, then impose them on a suitable historical load shape, modifying the load shape if necessary. Because of recent discontinuities in historical patterns, though, such a forecast procedure has not been well suited for applications involving rapid price escalation or the emerging emphasis on conservation and load management.

In contrast, the new model builds an hourly load shape from the ground up by the aggregation of projected end-use profiles. It is explicitly designed to trace the implications of developments brought on by rising energy prices, such as new energy management strategies and end-use technologies. The model is also capable of accounting for the load shape impact of changes in socio-demographic factors, economic activity, weather conditions, and the stock of energy-using equipment.

The REEPS hybrid model and the new load shape model built on end-use profiles are representative of the kind of work that is being done as modeling grows more sophisticated.

Model Applications

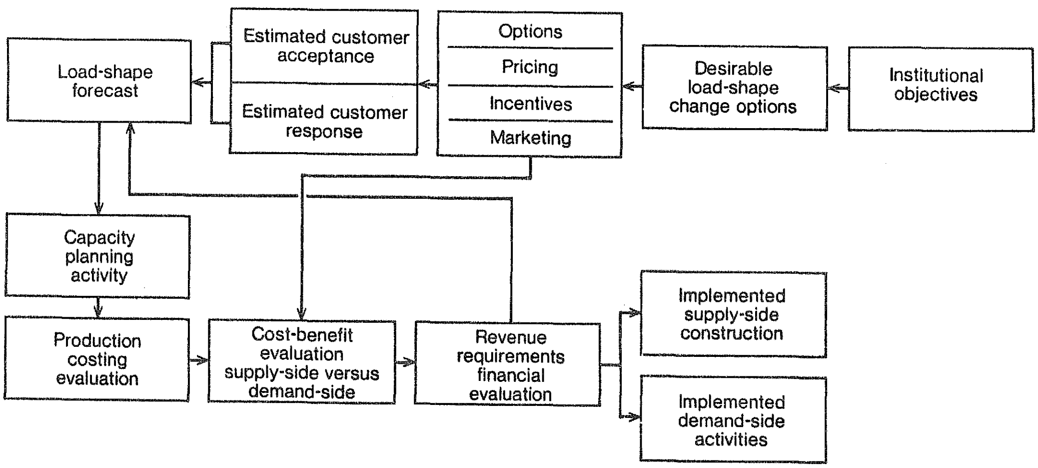
How are the new modeling methods being used to address utility forecasting needs?

The emphasis on forecasting detailed load shapes springs from the current utility priority on demand management programs as an alternative to capacity expansion and to improve finances. Part of the reason for this priority is the current climate of financial and regulatory constraints surrounding utility construction. Just as important, though, are continuing questions about the pace and extent of long-term load growth.

Demand management is an emerging concept in utility planning the tools and data for which are just now becoming available. Demand management entails total resource planning. It requires looking at institutional goals--including improved cash flow, improved productivity, or improved stockholder earnings and relating them to demand-side options. These goals have certain restrictions such as regulation, laws, and environmental constraints. The utility is further constrained by existing plant and facilities, financial resources as well as plant under construction.

Figure V

DEMAND-SIDE PLANNING



In demand-side planning, illustrated in Figure V, the utility planner operationalizes goals by examining the existing plant. The process subsequently includes considering potentially desirable load shape changes-the key to demand-side planning-which could be brought about by demand management in concert with supply-side alternatives. The potentially desirable load shape changes can be any one of a number including three general categories. First, the traditional load management options of peak shifting, valley filling, and load shifting. Secondly, strategic conservation and third, load growth or increased market share.

The demand impact of new electricty-based technologies is another question for the long-term. There is an emerging consensus that the U.S. manufacturing sector will respond to lagging productivity and fossil fuel supply uncertainties by a market-driven program of electrification. A major gap in our understanding of the impact of this trend occurs with respect to the indentification of the specific technologies likely to play a major role. EPRI's Energy Management and Utilization Division has a subprogram in place to address the hardware issues surrounding this new area. With its help, a technical planning study is now under consideration to develop a framework for analyzing which electrification technologies will be cost-effective in industry. The long-term implications of a switch to electricity-based technologies could be substantial.

In addition to these developments on the long-term forecasting scene, the utility need for efficient cash management has created a stronger emphasis on short-term forecasting. In the 1-12 month timeframe, the applications are varied: When is the best time for scheduled maintenance? When should the new stock or bond issue be released? On the other hand, in the 1-5 year timeframe, the most important application is rate determination.

Using a forward test year rather than a historical test year can ease the problem of regulatory lag. This practice of using forecasts instead of historical data as a basis for ratemaking is becoming more and more common, and a credible, accurate forecast helps in the acceptance of this approach. A new short-term forecasting model still on the EPRI drawing board will offer utilities a quantum jump in forecasting capability.

Four building blocks will go into creating the new model. The first will be adjustment of anticipated sales for weather changes, especially seasonal changes. The second will be data on the short-term impact of utility conservation programs. The third will be input on short-term price and income elasticities. And the fourth will be the use of innovative mathematical or statistical tools known as adaptive time-series techniques for the analysis of historical data on electricity use. These very powerful techniques are new in their application to energy forecasting.

Where to Now?

The current activity in modeling covers a broad range of efforts dealing with development of hybrid engineering/econometric end-use models, load shape models and market saturation models. These activities will remain at the cutting edge of our discipline for several more years. Several issues are beginning to evolve which will demand considerable attention in the years to come. Among them are commercial data needs, electrification and industrial productivity.

Interest in the commercial sector has been prompted by conservation and load management. Because of regulatory and political pressures as well as the public-relations benefits, utilities have initially centered most all of their activity in conservation and load management in the residential sector. Now that planning and impelementation mechanisms are maturing, attention has inevitably turned toward the commercial sector due primarily to the cost-effectiveness and potential for load shape change at each location. As this interest mounts, the lack of data on load shapes, vintage, population, size, level of business activity and other customer characteristics has become evident. Efforts will be mounted either by individual utilities or by a consortium of utilities to begin obtaining commercial data. Analysis and modeling activities will follow this.

Electrification or the concept of substituting electrical energy for processes previously energized by fossil fuels or for less energy intense processes so as to improve productivity and restore the cost and technology advantage of American industry is an important national issue. Modeling activities have been underway at some level in this area. However, a renewed higher level interest has begun due to the "sunset" vintage of many U.S. industrial facilities. The issues include what utilities and regulators can do to stimulate the energy marketplace so as to accelerate cost-effective electrification.

A number of complex issues are present in relating electrification, productivity and forecasts of world and U.S. industrial activities. Some of these include:

1) The availability of data on U.S. and world industries and modeling world product markets.

2) The deployment of the technologies already developed and the market penetration what they might achieve.

3) The development of new technologies and predicting their characteristics, costs and introduction.

4) Determining to what extent utility intervention will effect the above.

There is a practical limit to the quantity of data that is cost-effective to gather and manipulate in terms of the additional insight gained by the utility planner. New techniques are under study to reduce the amount of data required for a given level of accuracy, as well as to reduce the level of detail required in the ultimate forecast. The problems of forecasting and the needs for information are well documented. The industry is hard at work to develop tools, data, and techniques for accommodating these informational needs and to help utilities meet them in a reasonable, reliable, cost-effective manner.

The electrical industry has come a long way in elevating the sophistication and accuracy of models. These efforts have done a great deal to turn the art and science of forecasting into more of a science and less of an art.

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PAST, PRESENT, AND FUTURE ROLES OF A NATIONAL LABORATORY IN CAPACITY PLANNING

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I. Introduction

Oak Ridge National Laboratory is currently celebrating its fortieth year of existence. In describing the state of the laboratory at the inception of its fortieth year, Laboratory Director, Herman Postma characterized Washington's mandate for long-range, high-risk, high-payoff research and development as representing a "return to tradition" for Oak Ridge. Those of us involved in the "not-so-hard" sciences have felt internal and external pressure to demonstrate that our research endeavors and proposals for endeavors have not been frivolously misdirected toward short-range, low-risk, low-payoff work. In some ways, our role in capacity planning has been distinctly <u>nontraditional</u> for the laboratory--in that its genesis was as part of a diversification out of long-term "hard-science" atomic research. That genesis occurred as part of a two-decade laboratory diversification process, from which emerged major research thrusts in water chemistry and desalination, large-scale biology, civil defense, and environmental research. In another sense, our capacity planning role has been <u>logical</u>, given that Federal agencies and regulators charged with administering nuclear development programs have also been charged with assessing the need for nuclear power generation. In today's environment of <u>no</u> nuclear plant license applications and increasing dedication of utility and agency resources to short-term issues, the nontraditional and logical roles have seemed equally capable of evaporating. However, capacity planning activities have survived at Oak Ridge precisely because they have emerged as long-range, high-risk, high-payoff endeavors; and funding sources continue to want to look beyond the cashflow-fuel contracts-oriented time horizons of utilities. High payoff from the laboratory's perspective is the benefit from avoiding the <u>social</u> cost of being wrong--where social may include environmental degradation and health costs associated with choice of particular power provision options, and also a decline in real growth of incomes and living standards associated with continuous vacillation, delay, and postponement of capacity planning.

In my talk, I shall initially hop and skip (the intermittent anecdotal approach) across research areas of ORNL involvement in capacity planning. I shall then discuss what I call the "Client Problem." Should Oak Ridge provide services for the regulators and/or the regulated? If the latter, are we duplicative of private sector services? Next, I shall highlight what I think is persuasive evidence that there may be an upcoming electric capacity shortage--based upon a focused regional analysis and some general national observations. Fourth, I would like to spend the greatest part of my talk upon some new directions which ORNL is currently pursuing in forecasting the demand side of capacity planning--with emphases placed upon "variable level of detail" and "cost-effective for regulator operation." Finally, I shall conclude with a challenge to any and all mid- to long-term capacity planners to cost-effectively beat the weighted electricity growth prediction of GNP growth plus or minus regional development possibilities.

II. Research Areas in Capacity Planning

I shall employ the "perverse" approach to describing Oak Ridge activities associated with capacity planning. That perversity stems from my inclination to select and highlight activities bearing least resemblance to the paper topics listed for this symposium. I do so because of my desire to illustrate the social cost/payoff dimension of much of our work. I shall say a few words about work performed in five areas:

a. Integrated Power System and Load Control--Operation and Capacity Expansion Planning

b. Integrated Diversified Power Sources and Capacity Planning

c. Integrated Conservation and Capacity Planning

d. Need for Power Assessment of the Environmental Impact Statement

e. Sectoral End-Use Demand Modeling--the BPA Assignment

Divisions of Oak Ridge National Laboratory have advisory committees which are similar to "outside boards of directors" in their roles of evaluation and guidance of laboratory endeavors. Upon the recommendation of the Energy Division advisory committee, ORNL staff have initiated attempts to secure (internal and/or external) funding for an analysis of future U.S. electricity supply and use, and how electricity system options are impacted by, and impact upon, the institutional setting. Although I have not been a direct participant in the brainstorming for this project, I have benefited from the paper trail and general repartee associated with its inception. I mention this because the analysis of supply, use, and institutional setting draws from the five areas which I have chosen to highlight--and the repartee to date has identified critical issues which possibly should define a future role (for the laboratory) in capacity planning.

As many of you probably already know, Oak Ridge was a key participant--along with the Tennessee Valley Authority--in the development (under International Atomic Energy Commission sponsorship) of the Wien Automatic Systems Planning package (WASP). Since that time, Mike Kuliasha and others at Oak Ridge have participated in the refinement and evaluation of WASP and competitor capacity expansion planning tools. Over time, work initially focused toward capcity expansion planning has moved in the direction of load management. Four to five years ago, Mike (Kuliasha again) developed a dynamic simulation model for depicting power system operation with load control. He has moved from that base to consideration--in a formal modeling context--of integrated load management and capacity expansion planning. For example, one load management option, whose impact upon load profiles is currently being simulated, is the Annual Cycle Energy System (ACES) developed at Oak Ridge. This single-cycle heat pump and energy storage bin space-conditioning/water heating system--developed for residential and commercial sector applications--had very bad private (homeowner or builder) economics. That is, life-cycle cost analyses of ACES revealed very long paybacks and very low (sometimes negative) discount rates (or internal rates of return). However, the "social" benefit of ACES is that it significantly flattens the residential or commercial load profile. While it is by no means certain to me that the net present social worth of ACES makes it "socially" preferred to other space-conditioning options, I can at least suggest that the spectre of bad private/good social economics strains the current institutional framework surrounding the electric power system.

And in the context of the aforementioned brainstorming on future U.S. electricity supply and use, Tom Reddoch (of ORNL) has suggested a perhaps stronger and more practical institutional impediment to integrated load management and capacity expansion planning. That is, that at the utility level, load management has surfaced typically first in the rates department--as opposed to, in generation planning. Typically, the utility industry has never tampered with load. Therefore, in the dynamic political sense of difference between short-term and long-term planning, demand-side management has been slow in osmosing its way into the capacity expansion plans.

Mike Kuliasha and Tom Reddoch work as part of the Power Systems Technology Program at Oak Ridge. A major part of the program is concerned with end-use technologies, including research on distribution automation, customer-side thermal energy storage, and system integration of dispersed generating sources such as Photovoltaic (PV) devices or wind machines.

As part of the overall need to determine utility interconnection requirements of small, dispersed generating systems, a major program effort has been to identify and classify utility intertie problems for these systems. In 1982, investigation of PV power systems was focused on the effects of dc-to-ac power inverters on an electric utility distribution system. A model of a line-commutated inverter was used in the simulation of a proposed PV residential subdivision. Each of the 100 houses in this subdivision was to have a 6.6-kW PV system that would be connected to the electric utility system. A simulation study of the subdivision showed that the particular electric distribution system serving the subdivision was large enough to prevent any significant problems for the utility. However, key parameters were identified in the electric distribution configuration which, if not properly sized, could lead to adverse impacts. This work is continuing with the development of a tutorial for power engineers on the treatment of remote sources of harmonics on a distribution system.

The adequacy of present protection practices and hardware for electric distribution systems with dispersed storage and generation (DSG) devices has been examined. Operation of these systems is a concern for the electric utility industry because of the Federal laws, such as the Public Utility Regulatory Policies Act, to promote small, dispersed, customer-owned generation facilities that use renewable fuels.

Diversity in capacity options is also being considered by Mike Kuliasha as part of a Bonneville Power Administration/Hood River project in the Pacific Northwest. The Oak Ridge principal investigator for this project is Eric Hirst, whose current specialty resides in conservation program evaluation, and hence, in the integration of conservation and capacity options. I say "current specialty" advisedly, because Eric's name shall surface again and again in the course of my talk.

Eric has been involved in conservation evaluation projects for the Electric Power Research Institute, the Bonneville Power Administration, the DOE Residential Conservation Service program, and the Tennessee Valley Authority. Among other things, Eric has evaluated the impacts of Federal residential energy conservation tax credits, utility and broader-based home energy audit and loan programs, and energy audit programs for hospitals and other institutional buildings. A current future interest for Eric lies in exploring something about which very little "solid" is known--the relative effectiveness of conservation incentive options--such as zero or low-interest loans as compared to cash rebates. My interest in this area is in the social resource allocation benefit or cost of conservation incentives vis-a-vis investment incentives for other goods and services.

ORNL has been involved in the development and application of State-level electricity demand forecasting tools for 9 years. Development has included the fabrication of constant- and variable-elasticity State-level electricity demand models, the development of a utility service area disaggregation model to link State-level forecasts with utility-specific functional relationships, and the development of a load distribution model in which hourly load data and utility service area disaggregation forecasts are used to estimate future load duration curves. Applications of SLED integrated forecasting system components include use in environmental impact statements employing SLED results, public testimony employing SLED results, service area case studies employing the SLED integrated forecasting system, and other applications such as an evaluation of Regional Electricity Reliability Council demand forecasts and the assessment of need for Clinch River Breeder Reactor power--about which I shall have more to say later. Beginning in FY 1981, the emphasis of State-level electricity demand forecasting at ORNL shifted from model development and internal application toward the transfer of data and forecasting capabilities to regional/State users.

Sectoral end-use demand modeling at Oak Ridge has been my can of worms. Because I shall have much to say later about our residential sector work, I shall be brief here. In the buildings sectors--both residential and commercial, the major thrusts of my work at Oak Ridge have been upon improving the aggregation properties and logical consistency of our end-use models--while retaining the fundamental elegance of engineering process characterization of energy service equipment and thermal envelope technologies. My current assignment to the Bonneville Power Administration Division of Power Requirements follows on 2 years for which BPA has been my principal sponsor of end-use model development work. In this regard, BPA has taken up the slack created by the recent Washington-based DOE disdain for model development. I have personally felt rewarded by the BPA association because of Jeanne Yates Rimpo, John McConnaughey, and others' open-minded, competitively stimulated, attitude about end-use models and candidates for cost-effective preeminence in this area.

I would now like to come full-circle and return to the question of the future of the U.S. electricity supply system. Tom Reddoch, Mike Kuliasha, and others are analyzing power systems technology options--such as automated real-time system control capabilities, high-voltage d-c transmission, and both diversified and centralized capacity technologies--which hold the promise of breaking the spatial aspects of demand. For this to happen,"plug-in" supply options must be technically and institutionally integrated with localized load-management and conservation options. What are the fundamental non-technological issues associated with the practical evolution of a spatially forgiving power system? Tom Reddoch has identified three:

a. How will natural gas be deregulated, and what will be the impacts?

b. How will acid rain be "regulated," and what will be the consequent impact upon coal-fired generation?

c. What will happen with regard to rate-basing construction work in progress?

Two of these three are principally demand-side issues. The impacts of differing natural gas deregulation scenarios upon fuel switching and energy use curtailment were examined by ORNL staff (in an end-use modeling framework) as long as 2 years ago. The FERC allowance for CWIP in the rate base is a need for power assessment issue which involves (or should involve) methodologically sound considerations of impacts (what I shall later call deltas) associated with conservation options and load management options, as well as alternative power generation options.

III. The Client Problem for a National Laboratory

Analysts at Oak Ridge have historically maintained a nervous disequilibrium characterized by being perceived as fundamentally serving a nuclear-first institution, performing first-priority service to regulator agencies, and using Federal Government overhead resources to give away "public domain" modeling tools and services to whomever so requested in the private sector. What has changed that picture dramatically in recent years has been a new breed of laboratory scientist which first infiltrated Oak Ridge in the early 1970's, and a no-subsidy funding picture which has pushed ORNL staff in the direction of the grass roots. The resolution of the client problem has to do with the necessity for meeting public sector modeling objectives in tools provided also (or even primarily) for private sector use.

In my introduction, I mentioned the laboratory diversification into nonnuclear, nontraditional analytical, areas. One of those areas fell under the broad nomenclature of environmental research--but included activities such as development of methodological approaches to modeling energy conservation impacts, and econometric models for the need for power assessment of the environmental impact statement. The impetus for these endeavors was a series of open-ended collective soul- and purpose-searching seminars conducted (in the early 1970's at Oak Ridge) by David Rose, on leave from his nuclear engineering professorship at MIT. An alleged participant in these seminars was a fresh, young Ph.D. in mechanical engineering (from Stanford University)--Eric Hirst. Eric proceeded to get himself in trouble by publishing (or trying to publish) the first report that I know of which was recalled by the laboratory director--a report entitled "Electric Utility Advertising and the Environment." In this report, Eric explored what the implications of utility advertising at that time might be if the public followed the courses of action called for by the companies. Eric and I have since argued about the function of advertising--he arguing literally from a mechanical engineer's perspective and I arguing figuratively from an economist's perspective. Our differences notwithstanding, the "prolific radical" (as so labeled by researchers at the Institute for Public Policy Alternatives) Eric Hirst (and others similar but not so good as he) brought to Oak Ridge avenues to a new clientele interested in energy resource conservation primarily and resource exploitation secondarily, or even, negatively. In a sense, Eric had "his ducks in a line" when the so-called "Energy Crisis" opened a vast array of additional support for his position. It is therefore not in any way paradoxical that this free-thinking radical should have been the developer of the Oak Ridge residential end-use model--an endeavor which I consider to have seminally contributed to the integration of engineering and economics in energy demand modeling, in ways appreciated and yet unappreciated by the general modeling public.

From the laboratory "funded self-interest" perspetive, an additional problem with Eric Hirst was that he caught on so well. Technology transfer to both the regulator public, and to private-sector "Hirst-model" imitators was very quick. This as well as technology transfer of "soft-science" endeavors in other areas, has seemed to place ORNL in direct competition with consulting firms and others in the private sector.

Defining an appropriate and distinctive role for a national laboratory was exacerbated by the funding crunch which came in with the Reagan Administration. Then, not only did we find ourselves necessarily in the gray area of possible duplication of private sector services; but also, there was an increasingly "pitted" and vituperative competition among the national laboratories for public sector resources. In this atmosphere, which yet continues, there has evolved <u>no</u> clear and definitive role for ORNL in public and private client arenas.

Notwithstanding this, I have been very comfortable with my role at ORNL, and my efforts to unearth both public and private resources. Perhaps my lack of discomfort has been because, as a market-oriented economist, I spent my first days at the laboratory (incidentally coincident with Reagan's election) in fundamental disagreement with Eric Hirst's optimistic view of conservation program impacts--impacts supported by output of his end-use model. And yet, when I surveyed modeling alternatives offered then (and also now) by private sector vendors, I also found inappropriate attention paid to resource allocation impacts (including social costs) associated with programmatic conservation. I shall later describe our work in this area--in the development of an <u>evolutionary</u> successor to Eric's original residential end-use model. I would finally note that I think that this work may hold the promise of making programmatic conservation selectively more credible, because it places it upon a more defensible and logically consistent analytical base.

IV. An Upcoming Electric Power Shortage?

In two unrelated research exercises associated with mid- to long-term capacity planning, ORNL staff were asked to evaluate prospects for electric generating capacity demand growth. In one of these exercises performed for the Southeastern Region of the U.S., we also evaluated utility-level reported and surveyed capacity plans. In both analyses we found no evidence of decoupling of GNP growth and capacity demand growth. In the Southeastern targeted analysis, we found excess capacity persisting through 1990, but evidence of significant capacity shortages existing thereafter.

In an article which appeared recently in "Public Utilities Fortnightly," Craig R. Johnson argued for continued diminished electric power growth--"perhaps only 1 percent annually for several years." Rich Tepel, Dave Vogt, and I (of the ORNL Economic Analysis staff) were asked to validate or refute Johnson's claim in the light of our premonitions about structural change and economic growth in the U.S. economy, as well as any electricity demand forecasting evidence which we might have (lying around).

Of the several aspects of Johnson's article which we addressed, I would like to highlight two--on <u>historical</u> and <u>predicted</u> decoupling of electricity growth and real GNP growth:

(1) Historical--Johnson stated in the article that the "information economy" would bring about "substantially lower electricity requirements." On the premise that the "information economy" has been a developing entity, we looked at energy usage per dollar of real GNP for a recent historical period with an "energy crisis" thrown in--1978 to 1981. We found that decoupling had occurred with respect to other fuels (including fossil fuels)--from approximately 39 Quads per trillion dollar GNP (1978 $) to approximately 34 Quads per trillion dollar GNP. On the other hand, electricity usage remained relatively constant at approximately 4.8 Quads per trillion dollar GNP.

(2) Predicted--ORNL Energy Modeling staff employ sectoral end-use models--for residential, commercial, industrial, and transportation sectors--to make mid- to long-term projections of electricity and fossil fuels demand. These models embody some explicit characterizations of Johnson's so-called "basic structural changes" and may provide a quantitative verification or refutation of his conclusions. I should like to initially summarize how our end-use models deal with the electricity "low-growth" factors identified by Johnson; and subsequently, cite some fairly recent ORNL projections of electricity growth for the Nation. Johnson identified four "basic structural changes:"

a. The "long-term evolution in the nature of the domestic economy and its use of electricity" is embodied in the projected growth of commercial services sector floor space, and in projected improvements in efficiency of electrical appliances and processes.

b. The "saturation of electrical devices in the residential and commercial sectors" is, of course, an empirical conjecture. The sectoral models formalize this conjecture by taking actual base period saturations and projected fuel prices, income, population, and energy efficiency improvements, and in the context of economic behavioral paradigms examining a choice of increased electrification (e.g., more food freezers and computers per household) and switches to electricity from other fuels, simulate the electric appliance saturation over the forecasting horizon.

c. The "reversal of long-term trends in the real price of electricity" is not a "structural change" which enjoys a unanimous consensus in the forecasting community. For example, while no one can argue with the evidence of electricity prices in the recent past, future real price forecasts which we have received from Dale Jorgensen and Associates, Brookhaven National Laboratory, and the DOE Energy Information Administration suggest a significant flattening of future electricity prices relative to prices for fossil fuels.

d. "Changes in the mix of U.S. and world industrial production" are reflected in exogenously determined industrial output projections of growth in nine manufacturing sector industries, crops and livestock in the agricultural sector, mining and oil/gas extraction, and the construction industry.

Our latest characterization of these so-called "basic structural changes" in a modeling exercise occurred in September of 1982, and employed the EIA ARC prices. The ORNL results suggest an annual average growth rate in electricity consumption of 2.6 percent for the decade of the 1980's, and an annual average growth rate in electricity consumption of 2.8 percent for the period 1980-2000. Embodied in these cross-sectoral aggregates are 1980-2000 electricity consumption growth rate projections of 1.9 percent annually in the residential sector, and 2.3 percent annually in the commercial sector. Exogenously projected annual average GNP growth for the 1980-2000 period was 2.5 percent. Hence, ORNL modeling results suggest that future decoupling of electricity sales and GNP growth is unlikely to occur.

I reemphasize that these projections were made out of the context of a companion supply/capacity analysis for the U.S. However, in a targeted analysis--employing the same modeling framework with the addition of supply-side consideration of utility-level reported and surveyed capacity plans, reserve margins appropriate for the mix of generating plants, consequent dependable supply, and potential surplus or shortfall, we found evidence of an upcoming capacity shortage to exist with reasonably high probability. Our assessment occurred as part of a very recent, high-priority, high-visibility, short-timeframe assignment to evaluate marketability issues associated with Clinch River Breeder Reactor power.

With respect to the Southeastern Electric Reliability Council (SERC) service area not including Florida, we obtained the following results:

a. An appropriate reserve margin for the SERC-less Florida region--where the reserve margin is defined analytically as a function of the anticipated 1990's generating mix--is 23 percent.

b. 1990's reserve margins for SERC-less Florida subregions are as follows:
   Southern Companies--23 to 24 percent
   Tennessee Valley Authority--21 percent
   Virginia-Carolinas--24 percent

c. Committed capacity--defined as existing less planned retirements and under construction (not including nuclear plants less than 10 percent complete)--for the SERC-less Florida region is anticipated to be 115,028 megawatts in 1990, and 115,521 megawatts in 1995 and 2000. Planned capacity--defined to include existing plants less planned retirements, plants under construction, and planned capacity additions--is anticipated to be 116,600 megawatts in 1990, 120,181 megawatts in 1995, and 120,781 megawatts in 2000.

d. SERC-less Florida peak demand projections indicate existence of significant capacity shortfalls by 1995. For example, under our medium-price end-use modeling scenario, there exist planned capacity shortages of approximately 5,000 megawatts in 1995, and 20,000 megawatts in 2000. The low, medium, and high world oil price scenarios depicted are designed to be consistent with scenarios depicted by the Department of Energy, Energy Information Administration, and described in the 1982 "Annual Report to Congress." Under the Southern Regional Growth scenario, the SERC-less Florida Region is presumed to attain an average per capita income equal to the Nation's average per capita income by 2020.

I would like to note that the econometric forecasts (performed using the SLED model) were considerably higher than the end-use results. I discount the credibility of these projections because of problems (e.g., lack of characterization of explicit appliance efficiency changes) which I believe this "pure" econometric methodology shares with many other econometric methodologies.

V. New Directions in Load Forecasting

As I indicated in my discussion of Oak Ridge research areas in capacity planning, our best supply side analysts--among whom I would mention Tom Reddoch and Mike Kuliasha--are indicating fundamental capacity planning modeling and institutional issues surrounding the future U.S. electricity system which reside on the demand side. I don't think these guys are passing the buck, given their active, ambitious, and innovative participation in load management and power system operation and capacity expansion planning. Of course, the other primary contributor to demand management is programmatic conservation and the need exists for modeling tools which accurately depict programmatic impacts. I shall spend the greatest part of my talk discussing ORNL end-use modeling efforts directed toward this task. Moreover, I shall conclude my talk with a precautionary recommendation against using end-use modelings tools for other purposes for which they may not be cost effective.

A lesson of our participation in Need for Power Assessment work has been that our econometric modeling tools which produce energy demand forecasts underlying peak load forecasts have proved inadequate in three principal respects:

a. Their track record reveals a consistent upward bias in projecting energy demand growth.

b. They do not implicitly or explicitly account for nontraditional energy policy iniatives being undertaken at the state level, and for the interaction of policy and choices made.

c. They cannot monitor the "social" resource allocation cost of policy options considered and/or taken.

Obviously, a more elaborate structure than the simple econometric approach is suggested, in order to adequately characterize the latter two considerations. However, the resource allocation constraints faced by state regulators may preclude consideration and adoption of a full-blown "Monte Carlo/Microsimulation" approach. Oak Ridge has now developed a modeling capability in the residential sector which is flexible in its level of disaggregation detail, and which gives explicit consideration to social cost and resource allocation questions associated with conservation policy initiatives. Part of my assignment to BPA is to extend this methodology into the commercial sector. I propose this methodology as a cost-effective assessment alternative to present-regulator-practice econometric tools and to present-and-future utility practice micro-simulation tools.

The ORNL Residential Reference House Energy Demand (RRHED) Model is a mid- to long-term theory-based engineering/economic stock-adjustment model which simulates energy use and policy impacts over a 20- to 30-year time horizon. RRHED is an end-use model in the sense that energy consumption and policy impacts are forecast at the energy service provider level of detail--by fuel type and category of equipment. "Reference House" refers to the basic unit for disaggregating the usage extensity (i.e. floor space) of energy service. For the existing building stock, reference houses are single family, multifamily, and mobile home--with each reference type subject to independently considered (nonsimultaneous) energy-service equipment replacements. For new structures, references houses are disaggregated by building type (e.g. single family), and by assignment of fuel type to equipment type for space conditioning and water heating. This "high order" disaggregation permits analytical consideration of the simultaneous choice (for a new building) of building envelope thermal performance, space-conditioning equipment and efficiency, and water heating equipment and efficiency. Choice among 12 space heating systems (e.g. electric central forced air); choice of room, central, or no air-conditioning; and choice of water heater by one of four fuel types is considered. Application of household-survey determined decision rules for available combinations of space conditioning and water heating fuel and equipment has resulted in analysis of up to 81 configurations for each building type. Hence, new structures are disaggregated into up to 243 "Reference Houses."

An historical grievance of long standing with respect to end-use modeling has been the existence of "aggregation biases" of undetermined magnitude and direction. One aggregation bias (referred to as Type I) stems from the fact that aggregation of energy use totals across households by multiplying the average energy use characteristics of the housing stock and the number of households generally produces an answer different from the correct result obtained by a simple summation of energy use for all houses. A second bias (referred to as Type II) emanates from the prediction of energy use characteristics, e.g., appliance efficiency and usage, based upon average population characteristics, e.g., per capita income.

The reference house approach mitigates Type I aggregation bias by disaggregating the housing stock to enable prediction of average energy use characteristics at the reference house level, and then reaggregating with weights determined by the predicted incidence of each reference house in the stock. Type II aggregation bias is mitigated by estimation of energy use characteristics as a function of building-type specific household characteristics such as income and number of persons per household. Type II bias may be further mitigated by performing model simulations by income class--hence, resulting in a two-level stratification by income class and by class income per housing type.

The estimation of new and existing housing stock and size may occur through use of an ORNL submodel or user alternative. The ORNL housing submodel forecasts stock demands based upon age characteristics of the population, marriage and divorce patterns, household income, and other factors. However, a model practitioner may choose an alternative forecasting tool which stratifies (in addition to "by housing type") by income class, by age category, etc. Hence, the RRHED model can run consistently and interactively--employing feedback loops linking income and price movements, housing stock growth, and household energy service and energy service equipment demands--with service area, regional, or national econometric and demographic forecasts of economic activity, population trends, and patterns of household formation, dissolution, etc.

The reference house disaggregation is posed as a cost-effective alternative for mitigating aggregation biases to so-called micro-simulation models which utilize sampling techniques to select specific household portfolios with explicit appliance holding, socioeconomic, and demographic characteristics. On the one hand, because RRHED minimally requires significantly less household detail (as input requirements), it can be cost-effective in the analysis of policy impacts for which distributional effects are either not at issue or are demonstratively neutral. On the other hand, the micro-structure of RRHED new building usage, efficiency, and fuel and equipment choice makes the model amenable to input household stratification up to and including the results of a sampling exercise for selecting specific households. At whatever level of input detail, RRHED offers significant advantages to other modeling approaches in its ability to explicitly consider conventional and advanced energy service equipment, and the impacts of policy prescriptions for equipment and shell performance upon the choice of fuel and equipment saturation.

The ORNL Residential Reference House Energy Demand Model is theory-based in the sense that it simulates on the bases of satisfaction of logically consistent economic paradigms characterizing household decisionmaking and of energy service production possibilities stemming from engineering technological process analyses. Logical consistency is established between an intertemporal utility maximization hypothesis which underlies fuel and equipment choice and a life-cycle-cost minimization hypothesis underlying the capital stock usage/efficiency/capacity decision. The engineering process analyses generate shell and energy service equipment isoquants which are consistent with a broad family of underlying household energy service production functions or correspondences. Analysis of policy effecting new structures can be done in a constrained optimization framework which produces cost-of-conservation shadow price increments to the fuel prices confronting the builder or homeowner decisionmaker.

RRHED is a stock-adjustment model in the sense that energy service capital stock and its efficiency characteristics change with respect to base year values. The baseline case is established using survey data, historical series, and a limited amount of informed judgment. The primary output of the model is total residential energy consumption classified by housing type, fuel, and end-use. However, because the model is capable of extensive "with and without" analysis of conservation programs, a significant implicit output of the model is characterization of policy impacts reflecting the primary output detail capabilities. RRHED currently deals with four fuel types (with structure in place and analysis in progress to permit explicit characterization of a fifth fuel--wood), nine end-uses (with structure for ten end-uses) and two housing states. The model also calculates estimates of new equipment penetration, equipment efficiencies, structure thermal performance, usage factors, fuel expenditures, equipment costs, and incremental costs for improving thermal performance of new and existing housing units.

At each of the two levels of reference house detail (for existing and new), RRHED consists of four conceptual structural components--building stock, usage, technology/efficiency choice, and fuel-and-equipment choice. An accounting equation bridges the two levels of disaggregation and relates the structural components. The building stock component forecasts the extensity or breadth of energy utilization by deriving total residential floor space. As I previously mentioned, this component exists as a submodel and may be substituted for by a user alternative. The building stock component supplies exogenous inputs to the remaining integrated structural components. The usage component projects the long-run and short-run intensities of energy utilization (e.g., space heating ambient temperature). The technology choice component, conditioned by the long-run usage expectation, determines the economically optimum selection of building envelope and end-use equipment. The economic optimum may be constrained by prescriptive performance standards for equipment and/or shell, or by an aggregate performance objective (e.g., a "Design Energy Budget") for the building. The efficiency choice associated with various equipment types (e.g., heat pump) and fuel choices, as well as the shadow price associated with policy constraints on an economic optimum, "impact upon" the capital and operating cost attractiveness of employing these fuel-and-equipment combinations--which is a basis, for fuel-and-equipment choice (in the fuel-and-equipment choice component). For simultaneous efficiency choices in new structures, logical consistency is established with a nested logit fuel-and-equipment choice involving space conditioning, water heating, cooking, and clothes drying end-uses. Finally, the accounting equation relates the output of the four components to determine the primary output--residential energy use.

RRHED was preceded by the ORNL Residential Energy Demand Model originally developed by Eric Hirst and Janet Carney for the purpose of predicting energy conservation policy impacts at a geographically aggregated level (i.e., Nation or Federal region). Objectives characterizing initial model development included simplicity of structure; ease of understanding; ease of implementation, repetitive application, and interpretation; cost-effectiveness relative to other modeling tools; and clarity and availability of documentation. A measure of the effectiveness of the accomplishment of these goals was that the soon-to-be-called "Hirst model" enjoyed wide distribution and application. The model was employed for analysis of policy impacts, determination of programmatic expenditures, and forecasts of energy demand at the end-use and fuel-type level of detail. At the same time, the model served as a "benchmark methodology" for the development by private-sector vendors of "carbon-copy" and more sophisticated models for use at more geographically disaggregated levels of analysis (e.g., utility service areas). With the widespread technology transfer and programmatic applications emanating from development of the Hirst model, it is not surprising that the model became an early target for evaluation and validation. The impact of these exercises (performed by nationally known economists and statisticians under sponsorship from the National Bureau of Standards, the Energy Information Administration of the Department of Energy, the Electric Power Research Institute, and others) has been to induce additional technology transfer to private-sector model builders, and to stimulate the evolutionary upgrading of the original product. That upgrading has occurred in the context of retaining the identified strengths of the original Hirst modeling approach, responding to the salient weaknesses identified in the evaluatory process, and drawing from insights and techniques of private-sector vendors.

The basic approach to end use modeling is to identify energy consumption by energy using activities and then aggregate over these activities to obtain overall consumption. This approach is based upon the idea that the stock of energy using appliances (with each "appliance" associated with an end-use) in a household can "indicate" the energy consumption of that household. The disaggregation provided from energy consumption by end-use, instead of lump sum consumption, is valuable in the analysis of detailed conservation programs. Energy projections may be obtained by carrying forward economic and engineering data with exogenously determined modifications to these data occurring over time. Alternatively, energy projections may occur on the basis of theory-based endogenously determined modifications of input data and/or parameters. A combination of "accounting-based" projections (e.g., impacts of shell-retrofit programs in the RRHED model) vis-a-vis theory-based projections (e.g., RRHED model projected heat pump penetration in new residences) may be employed because it is deemed cost effective in terms of model structure and "run" characteristics, or because of insufficient data to support a theoretical construct. Moreover, as stated previously, application of the end-use modeling basic approach necessitates aggregation of energy use totals across households. The original Hirst model accomplished this aggregation by multiplying the average energy use characteristics and household size by the number of households. This engendered the fundamental "aggregation bias" criticism of the Hirst and Carney modeling approach. For this reason, end-use modeling (at Oak Ridge and among private vendors) has moved in the direction of simulation approaches involving the summation of household prototype energy use totals for which each prototype represents increasingly smaller segments of the housing stock.

The ORNL Residential Reference House Energy Demand Model represents the current evolutionary state of residential end-use modeling at Oak Ridge. However, ORNL staff have developed a separate residential end-use model (with restricted new structure capabilities) which references the existing housing stock by five-year vintage segments, and "tracks" appliance survival in low-, medium-, and high-efficiency categories. Expansion of RRHED structure to include the referenced vintage stock is anticipated within calendar year 1984. However the cost-effectiveness of the integrated structure will determine whether or not it is adopted as an "official" successor to RRHED.

The original Hirst model has withstood much derision and abuse from so-called independent evaluators who, in the best spirit of American entrepreneurship, have put forth their own models as alternative forecasting and policy analysis tools. I think that the fact that Eric Hirst's model survives as the resident "whipping boy" for the profession is a tribute to its enduring strengths rather than identified weaknesses--about which Eric's initial structure has been sufficiently flexible to permit straightforward resolution. I consider the Residential Reference House Energy Demand Model to be an honorable evolutionary successor to the original Hirst conception--a successor which has extended the explicit technology characterization and consideration concept in the directions of simultaneous considerations for simultaneous decisionmaking, and a technology isoquant envelope characterization of conventional and advanced end-use equipment technical options.

An example of the relevance of these capabilities for accurate determination of programmatic conservation impacts is the characterization of prescriptive shell and equipment standards (e.g., ASHRAE 1980A) for new structures. In this regard, as a market economist sufficiently reactionary to display a photograph of Milton Friedman above my desk at Oak Ridge National Lab, my initial concern about the state of end-use modeling of standards was that the true "resource misallocation" social cost was not being depicted in any way. What I am talking about in graphical and economic analytical terms is the difference between a tangency of an isoamenity isoquant (perhaps representing 72°F space heating) and the lowest possible life cycle isocost line and (alternatively) the policy constrained intersection between the same isoquant and some higher (more expensive) life cycle isocost line. My initial work in end-use modeling at Oak Ridge was to model this policy constrained optimization--for residential and commercial sectors--and associated social premium fuel cost impact for technology choice. However, as things happen in this business, it took Ken Corum of the Pacific Northwest Regional Power Planning Council to point out to me that it was logically inconsistent to model the social cost impact upon technology choice without also extending the analysis to the impacts upon fuel-and-equipment choice and equipment saturations. We have done so at ORNL by aggregating the prescriptive standards for shell and simultaneously considered end-uses, determining the social cost Lagrange multiplier shadow price associated with each particular (of 81 possible per building type) configuration of equipment and shell, and incrementing fuel cost in the nested logit analytical fuel-and-equipment choice by the shadow price. What you get--which is very important--from all this is indication that a solitary tight standard on electrically heated houses may work against the market attractiveness of these houses--in a counteractive fashion to the operating cost advantages brought about by the standard.

VI. Conclusion--Beating the GNP Signal and Regional Development Economist

Thus far, I have discussed Oak Ridge involvement on both the supply and demand sides of capacity planning. In my section II discussion of research areas in capacity planning, I intimated past, present, and future supply-side actor roles in the integration of capacity expansion planning as conventionally tooled with load management, diversified power sources, and conservation. In sections IV and V, I discussed rather extensively past and present roles involving me, firmly entrenched on the demand side of capacity planning. As a demand-side analyst, I would again like to ask myself--as I did in part in my section III discussion of the client problem for a national lab--about the appropriate future role for a demand-side analyst in capacity planning.

In general, demand forecasters have given utilities, utility organizations, regulators, and any other potentially interested parties the very hard sell. We have done this, partially if not primarily, on the basis of how poorly we have done in the past--and the notion that more dollars for more sophistication will redeem us and be well spent. I continually hear about the so-called "education process" and how well we have succeeded at proving our necessity to the utility community.

I think our cost-effectiveness at mid- to long-term demand-side capacity expansion planning has been oversold. In saying this, I would like to distinguish between absolutes and deltas--where deltas represent changes in peak demand growth brought about by management of load profiles, conservation programs, etc. If I were to be held to account for a mid- to long-term peak demand forecast--an almost unheard-of and unimaginable accountability, in a not unreasonable economic and energy health scenario of little perceived service area need for load management or programmatic conservation, I would be strongly inclined to base my growth forecast upon a simple three-step analytical procedure:

a. Assume that service area peak demand growth will closely follow real GNP growth.

b. Adjust that assumption in accordance with a regional economist's analysis of how service area income growth prospects differ from national income growth prospects.

c. Additionally adjust the assumption on the basis of saturation of electrically powered energy service equipment relative to national averages.

Not only do I claim that this procedure would be cheaper; but also, I claim it holds the promise of being more accurate for the stated purpose. On the one hand, demand models have a strong tendency toward error compounding in the projection of absolutes, which tends to move the energy growth forecast away from the growth pattern of key energy growth determinants (such as income). On the other hand, attention paid to complex demand models bears an opportunity cost of attention paid to very important regional growth factors (such as service area "high tech" education infrastructure and the labor union climatic impact upon the potential for indigenous entrepreneurship).

I believe that the appropriate role for demand modeling in capacity expansion planning is not significantly different from the Oak Ridge-Eric Hirst inspired initial role of analysis of national programmatic conservation benefits. That is, given a clearly perceived service area necessity, the role lies in the analysis of peak demand growth deltas achievable from managing load and mandating energy conservation. And, accepting this as a legitimate role which we may or may not perform cost-effectively, I think we must make our analysis credible by accounting the social cost impacts of our policy prescriptions.

(WP-PN-5593A)

A SYSTEM PLANNER'S VIEW OF LOAD FORECASTING AND GENERATING CAPACITY EXPANSION

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Symposium on Computer Analysis of
Electric Load Forecasting and Generation Capacity Expansion
Columbus, Ohio, September 14-16, 1983

I welcome the opportunity to be here today to participate with you in this symposium. The National Regulatory Research Institute is to be commended for bringing together, in one forum, two related subjects that I, as a system planner, find of vital and timely interest. I also appreciate this opportunity to share with you some of my views on both these subjects -- that is, load forecasting and generating capacity expansion -- and on the interrelationships that exist between them.

In this presentation, I will not delve into an examination of the technical details involved in carrying out the kinds of analyses that are being described in the various papers being presented at this symposium. Rather, I will discuss some of the broader principles pertaining to such analyses from the power system planning perspective.

To begin with, let me pose the question "what is power system planning"?

To answer this question, we need to first define the basic terms involved, by asking ourselves what is a "system"? And, what is a "power system"?

Webster's definition of a "system" is

> "An assemblage of objects united by some form of regular interaction or interdependence,
> or
> a complete exhibition of essential principles or facts, arranged in a rational dependence or connection,
> or
> a complex of ideas, principles, etc., forming a coherent whole."

So, to paraphrase Webster, an electric power system is -- in a limited sense -- an assemblage of generation, transmission, and distribution facilities, designed in such a manner as to operate as an interdependent, coordinated whole in supplying electric power requirements in a certain geographical area.

In a broader sense, however, an electric power system can be defined as a set of interrelated conceptual, as well as physical, elements, including -- in addition to physical facilities -- such factors as load characteristics and rates of growth, availability of fuel resources and their costs, power plant efficiencies, outage rates and operating costs; all viewed in the dimension of time, i.e., in terms of today, next year, and ten years hence.

Power system planning, in turn, involves analysis, evaluation, and synthesis of the various elements of the power system -- in terms of their conceptual and physical attributes -- so as to achieve certain optimizing goals over time. In this regard, in the very broadest sense, the primary elements involved in the system planning process are: (1) the customer's electric load -- which represents the product that the utility is responsible for supplying, (2) the generation system -- which represents the source of that product, (3) the transmission system -- which represents the means by which the product is delivered from the generation source to the customer, and, in addition, (4) the cost involved in supplying the product to the customer, and (5) the impact of time on each of the previous four elements.

With these elements in mind, then, the broad objective of power system planning is to provide -- over the course of time -- the most reliable electric power supply, at the lowest possible cost, and within the overall framework of societal goals and objectives, including, in particular, the objective of preserving -- and optimizing the utilization of -- our nation's resources, including not only energy and the natural environment, but also capital and labor.

As I am sure you can appreciate, the planning of a power system is obviously not an engineering handbook technique or routine mathematical exercise. Power system planning differs inherently from planning in other industries where decisions for expansion can be made solely on an evaluation of the market, or where it may be decided not to sell a certain product or serve a particular area. In the power industry, however, the opportunity to serve is also the obligation to serve. Sound planning must be comprehensive and imaginative. It requires a knowledge not only of the technical characteristics of equipment or the increasingly sophisticated tools and techniques of analysis, but also an understanding of the needs of the customer and, even more basic, of the economic and social forces shaping our industry.

Now, in discussing the general framework of power system planning, we need to take note of the essential nature of the product of the electric utility industry.

First, our highly developed industrial society is greatly dependent on the availability of electric power supply. This has been true in the past and will continue to be true, even more so, in the future.

Secondly, because of its unique characteristics, electricity must be produced -- i.e., made available -- at the instant it is consumed. In this regard, the consumer expects -- and, indeed, takes for granted -- that electric power <u>will</u> be instantaneously available, when the switch to operate that certain light, appliance, or special equipment is turned to the "on" position.

These two facets regarding the essentiality of electric power supply have a bearing on an important planning concept that is rooted in both the technical and time-related aspects of power system planning. This is the concept of lead time, which is the time required to complete a project once the decision is made to proceed. In the electric power industry, because of the technological complexity of the equipment involved and also because of the oftentimes cumbersome and very time-consuming licensing and certification requirements, lead times are very long for major power supply facilities: typically five to ten years or more in the case of generating facilities, and four to six years in the case of major transmission. Such long lead times have major implications in the planning process, particularly in view of the relatively short lead times for those customer facilities that utilize electric power. With residential, commercial, and most industrial construction requiring only up to one to two years to complete, actual construction of new generating facilities must be started several years prior to the time when the eventual user of the electric energy to be produced by these facilities makes his decision to proceed with air conditioning his home, building a new shopping center, or constructing a new, large manufacturing plant.

Earlier, I suggested that sound power system planning requires, among other things, an understanding of the economic and social forces shaping the industry. Such understanding is, of course, an essential aspect of load forecasting and bears out the fact that load forecasting is, after all, an intrinsic part of the planning process. Indeed, it constitutes the very first step in that process and provides the basis on which power supply facilities are planned.

In this connection, we are all aware that changes in the level of electricity consumption are influenced by many interrelated factors. These include, for example, economic activity, population trends, household formations, the weather, the saturation levels and efficiencies of various electrical appliances, technological innovations, changes in the relative price and availability of electricity compared to other substitutable energy sources, and shifts in basic human values and lifestyles. Significantly, of all these factors, the one that exerts the greatest influence on growth in electric load is economic activity. In the broadest sense, it is the economic forces operating in society that determine the overall size and vitality of the marketplace within which electricity-consumption decisions are made.

The nature of the correspondence between electricity consumption and economic activity -- as measured by the Gross National Product -- is illustrated in Exhibit 1. This exhibit, which covers the period 1960 to 1982, clearly shows that, historically, a relatively close relationship has existed between real GNP and the nation's electricity use. The exhibit also provides a visual comparison of the trends which occurred in both economic activity and electricity use both before and after the Arab Oil Embargo of late 1973 to early 1974.

As Exhibit 2 indicates, in the pre-embargo years 1960 to 1973 -- which was a period of essentially uninterrupted, steady economic growth -- real

GNP grew at an average annual growth rate of 4.2%, while another economic indicator, the Federal Reserve Board's Index of Industrial Production, grew at a 5.3% rate. The corresponding growth rate in the nation's electric energy consumption was 6.7%. However, in the post-embargo period 1973 to 1982 -- which included some relatively severe recessionary times resulting from a host of unforeseen developments -- each of these average growth rates dropped dramatically: The growth rates for GNP and Industrial Production dropped to only 1.8% and 0.7%, respectively, while the growth rate for electric energy consumption dropped to 1.4% per year.

It also should be noted that the change in the rate of growth in the FRB Index of Industrial Production in the post-embargo period, as compared to the pre-embargo period, reflects the particularly severe impact of these recessionary times on the industrial sector of the nation's economy.

During the past ten years, concurrent with the experience of the previously unforeseen declining rates of actual growth in the economy and in electric energy consumption, the forecasts of future electricity use have been progressively declining, as shown in Exhibit 3. Projections of growth in summer peak demand for the nation have been successively lowered since 1974: from 7.6% per year, envisioned in 1974, to 2.8% per year, based on the most recently reported utility forecasts. These downward revisions in the forecasted growth rate of peak demand represent the dynamic response of the forecasting process -- which is inherently complex -- to actual experience and to changing perceptions of the future.

Evidence of the effect of the dramatic shifts which have been occurring in economic growth is given on Exhibit 4, which compares actual GNP for the year 1982 with the range of forecasts made by several prominent forecasting organizations, starting with the first quarter of 1981. Even in the short term, the economic forecasters have missed the mark and have not been in total agreement.

The uncertainty still inherent in forecasting economic activity is evident from Exhibit 5, which portrays a range of forecasts of GNP for the years 1983 to 1986. The highest of these forecasts projects that GNP will grow at an average annual rate of about 4.4% from 1982 to 1986, while the lowest of these projections reflects an average growth rate of 2.2%.

In connection with such uncertainties, it is important to note that, over the long term, the impact on future power supply programs of even a small change in the average annual growth rate in electricity use can be significant because of the compounding effect of such a change over time. An example of this effect can be seen in Exhibit 6.

In the example shown, a change in the growth rate from 3.0% to 3.3% in the annual peak electric demand for the U.S. over the ten-year period 1982-1991 results in a change in the increase in peak demand requirements from 130,000 MW to 145,000 MW. The additional 15,000 MW translates to a 12% change in the increased requirements.

From all of this, it is evident that the forecasting of electric load is a dynamic process that is fraught with uncertainties. While these uncertainties stem from a variety of sources, they can be classified as basically two types:

(1) modelling uncertainties, which reflect our inability to simulate perfectly the real world, and which stem from an imperfect understanding of the causal structure of events affecting electric load growth, and

(2) uncertainties regarding societal change, which reflect our inability to know in advance all that the future holds.

Prominent among the second type of uncertainty is that associated with the future direction and effects of government policy changes and private-sector responses which influence the economy. Thus, although we may know and be able to analyze and try to understand the past, we cannot really know with any certainty the future. Of course, we may project various future scenarios, and then analyze them, but any anticipation of future events is still subject to error and uncertainty. The power system planner -- just like everyone else -- is not privileged in this regard, nor is he blessed with a special gift of clairvoyance. He simply cannot be certain of the future.

Indeed, the task of making projections into the future is not made any easier for the power system planner by the fact that the electric power industry -- today -- is facing changes and uncertainties on a scale unparalleled in its history. In this connection, the past several years have been marked by increasing uncertainties in all facets of power supply. This includes uncertainties regarding the bringing into service of new power supply facilities -- beset as they are now by environmental opposition, financing problems and extended procedural and licensing requirements. These factors have increased the minimum forecast periods associated with the construction of such facilities and have added increased uncertainty to the accuracy of load forecasts that must be relied upon for decision-making. In addition, the events following the oil embargo of late 1973 and early 1974 raised additional uncertainties regarding the future energy demands of the nation, as affected by conservation, energy substitution, and a host of other considerations.

In view of all this, the system planner learns to live with uncertainty as a permanent ingredient in his day-to-day work. He learns to distinguish between the sustained, long-term trends and transient, short-term effects. He learns that there is no way to come up with a precise, all-encompassing, rigid, long-term plan of system development that can be kept unchanged -- once made -- until the time of its implementation, without prohibitive penalties to the power system, to its customers, and -- indeed -- to the society at large. He learns -- finally -- that, out of several alternative plans for future system development, the plan with the greatest flexibility for change is -- in general -- preferable to all others.

In spite of all the difficulties that may be involved in projecting future trends, conditions, and requirements -- and in formulating plans for the future development of power system facilities to meet these requirements in the best way -- the system planner has no choice but to try to do so. At a fixed point in time -- determined by the lead times involved -- a decision must be made to proceed one way or another.

In this connection, the concept of "lead time" and the concept of "uncertainty" both play an important role in the timing of new generating facilities on a power system and in the determination of a system's generating-capacity reserve requirements.

Since, as I pointed out earlier, it takes five to ten years to build a major power plant, a decision to proceed with its construction -- and to dedicate the necessary capital funds -- must be made at least five to ten years prior to the time when the output of the plant is expected to be needed to meet the customers' additional requirements for electric power. Whether that additional generating capacity will -- in fact -- be needed at that particular point in time is never certain beforehand. It cannot be certain simply because the need for additional generating capacity five or more years hence depends on a multitude of circumstances, each of which -- when projected five or more years into the future -- is itself subject to error and uncertainty.

The need for additional generating capacity several years hence depends -- to begin with -- on the expected load growth over the period in question. Beyond that, it depends on the seasonal, monthly, weekly, daily, and even hourly pattern of electric demand, as it will be at that particular future point in time; it depends on the future availability performance of the system's generating capacity, both the capacity already on line and that still to be added during the intervening period; it depends also on the extent to which the power system -- several years hence -- will be able to rely on emergency support from its interconnections with other utility systems. All of these factors, while known or easily determinable for the past, can be only roughly estimated for the future.

While we use, in planning, many elaborate and complex analytical techniques to help us understand the interaction between the various factors that influence future load growth and capacity reserve requirements -- and, therefore, influence the timing of new capacity additions -- all these techniques merely help us predict what would happen only <u>if</u> certain assumed conditions occur first. The "if" is of crucial importance here, since -- as long as we cannot be certain of our assumptions -- we cannot be certain of our results.

How, then, are we to judge whether, as part of a capacity expansion plan, the construction of a major, new generating facility is to be started this year, next year, or two years hence? With the cost of a single, large generating unit approaching, in some cases, one billion dollars or more, this is literally a "billion-dollar" question. It is a question of vital concern to the consumers of electricity, who eventually will need to carry the cost of the new facility; to the electric utility, having the responsibility to provide adequate electric service in a given geographical area and also having the burden of scraping together the funds necessary for going forward with the construction; and to the regulatory commissions, which have the dual responsibility of assuring adequate electric power supply at reasonable cost to the consuming public, while at the same time protecting the rights of the investing public to a reasonable return on its investment in utility securities.

In situations such as this, the tendency is to search for "an easy way out", to look for a single index, a single number or a set of numbers, that would provide the answer to the difficult question at hand. It would be nice to have a single index, or a single number -- such as 15% reserve, or 20% reserve, or "loss of load once in ten years", or "loss of load once in five years" -- that would determine for us how much generating capacity a power system ought to have five, or eight, or ten years hence. It would make the problem a great deal simpler for electric utilities, in explaining their need for additional financing to utility regulators; for utility regulators, in judging a utility's need for such financing and in explaining such need to the general public; and for the general public, in appraising the performance of its electric utilities and its regulatory commissions.

The fact of the matter is that there is no single, simple answer to the question of whether the construction of a major, new power plant ought to be started this year, next year, or two years hence. The answer depends on a multitude of factors that vary from one particular instance to the next. Many of these factors elude numerical interpretation entirely. Application of judgment remains an all-important ingredient.

In this regard, the judgmental weighing of the consequences of being wrong in following one alternative path vs. another is particularly helpful in deciding which path to follow. When applied to the question of forecasting future electric demands, determining future capacity reserve requirements, and establishing the timing of new generating capacity additions, such judgmental weighing of where the public interest lies will invariably point toward having temporarily too much generating capacity rather than too little.

Construction of new generating capacity may be slowed down, following a clear showing of reduced growth in electric demand or reduced need for generation reserves. However, construction cannot be accelerated beyond its inherent lead-time constraints, regardless of how desperately society may find itself needing the very generating capacity that it failed to develop in a timely manner.

Clearly, power system planning is a vital and challenging task. In view of the uncertainties involved, if the demands of society for electric energy are to be met, then it is important that the plans for meeting those demands recognize the need for both flexibility and the application of informed judgment.

Exhibit 1

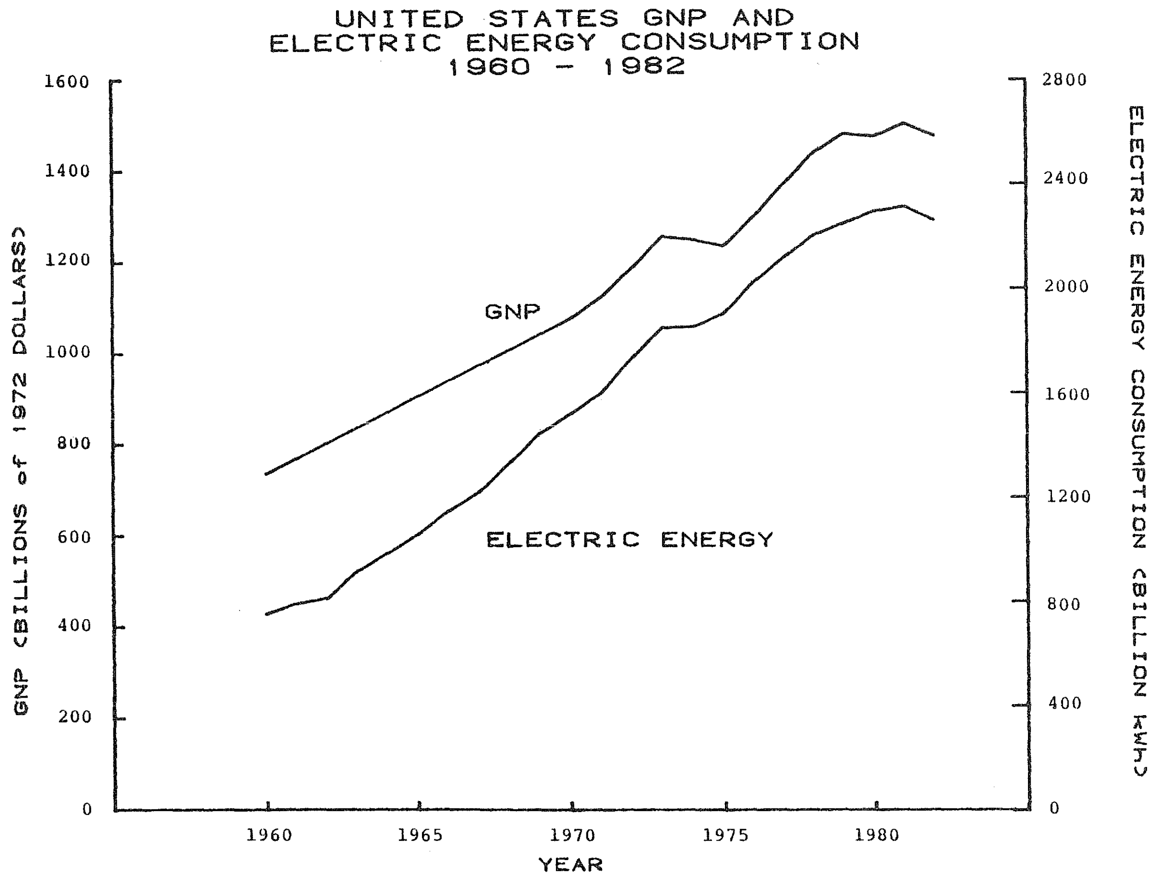


Exhibit 2

Average Annual Growth Rates
U. S. Economy and Electric Energy Consumption
1960-1973 and 1973-1982

	1960-1973 %	1973-1982 %
Real Gross National Product	4.2	1.8
FRB Index of Industrial Production	5.3	0.7
U. S. Electric Energy Consumption	6.7	1.4

Exhibit 3

Summer Peak Demand Projections
Comparison of Annual Ten-Year Forecasts
(Contiguous U.S.)

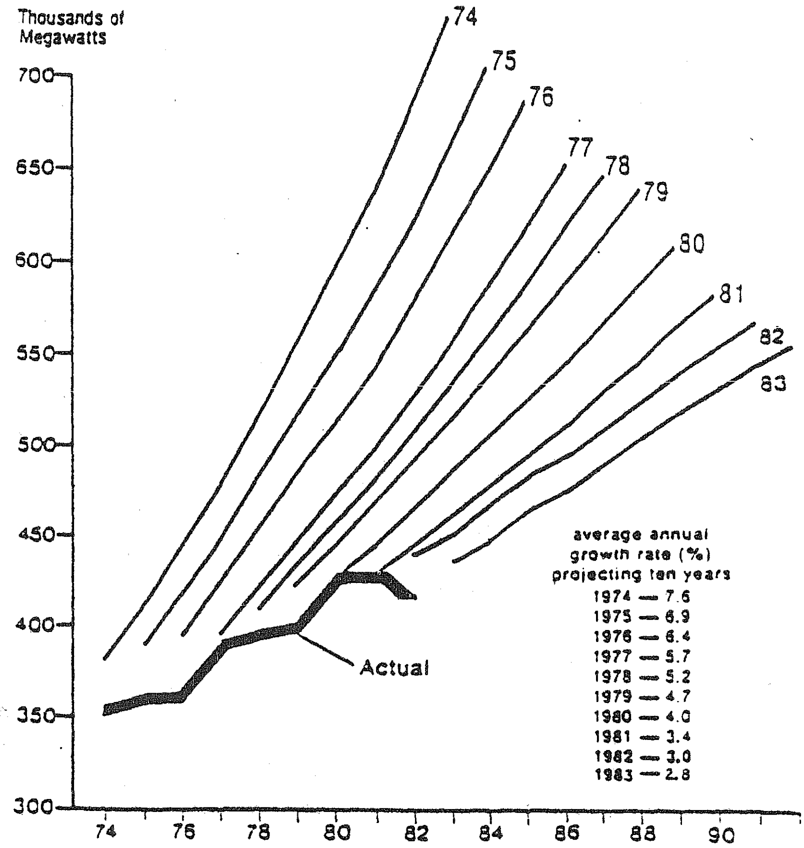
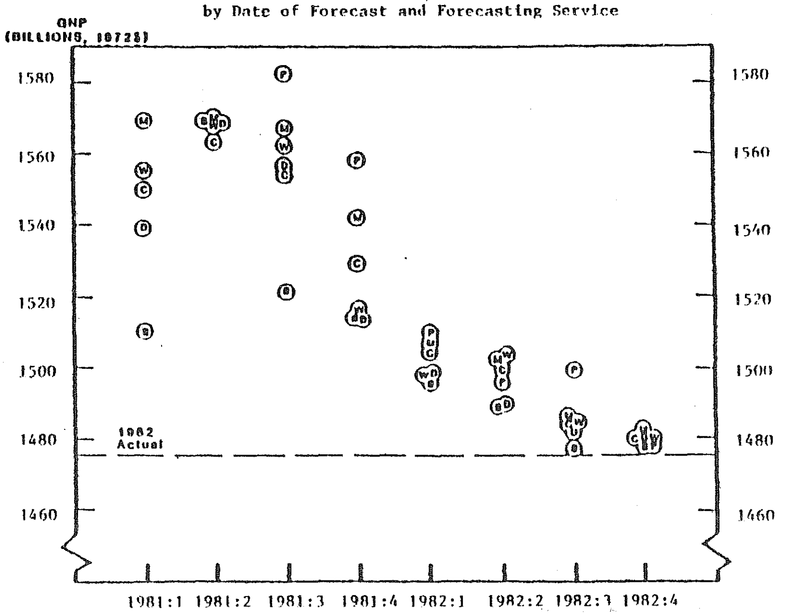


Exhibit 4

Short-Term Forecasts of 1982 GNP Compared to Actual 1982 GNP
by Date of Forecast and Forecasting Service



(B) : THE CONFERENCE BOARD
(M) : MERRILL LYNCH ECONOMICS
(C) : CHASE ECONOMETRIC ASSOCIATES, INC.
(P) : PREDICASTS, INC.
(D) : DATA RESOURCES, INC.
(W) : WHARTON ECONOMETRIC FORECASTING

Exhibit 5

Comparison of Forecasts of U.S. GNP,
by Source, for the Years 1983-1986

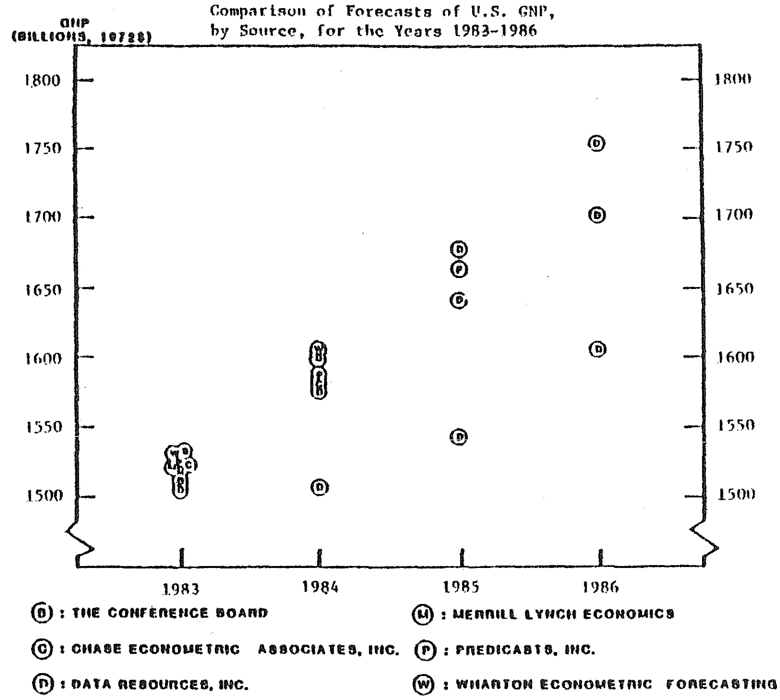
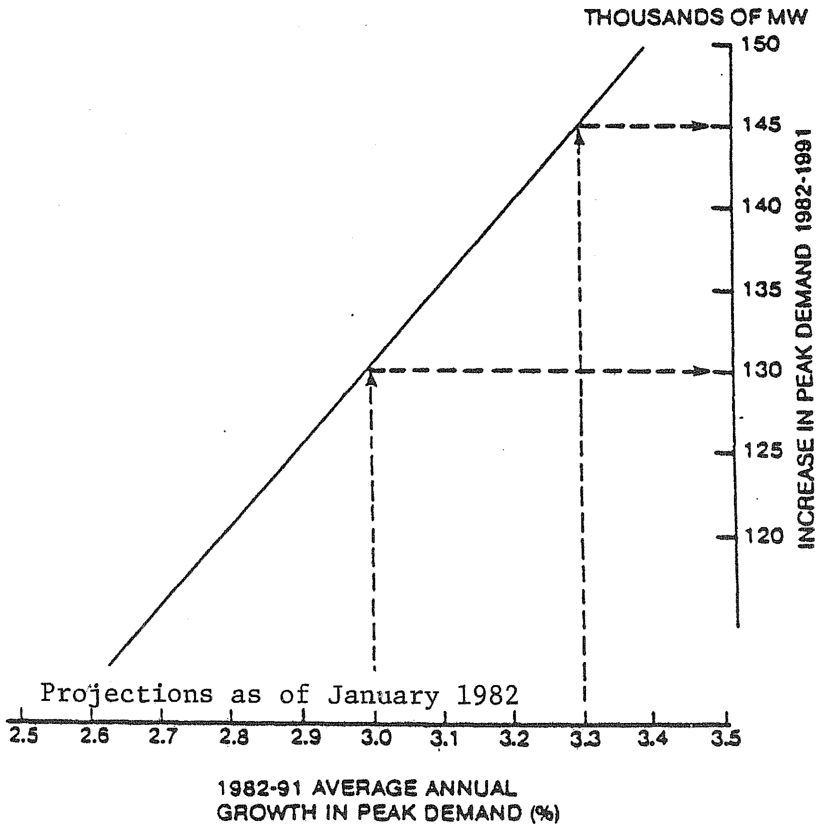


Exhibit 6

SENSITIVITY OF PEAK DEMAND INCREASE
TO CHANGE IN GROWTH — 1982 - 1991



THE MEASUREMENT OF TIME VARIANT LINEAR TRENDS
IN OHIO SECTORAL ELECTRICITY DISPOSITION LEVELS

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I. Introduction and Objective

The time paths of many observed economic data series such as the sectoral sales of electricity in the U.S. or Ohio, as well as the revenues realized from such sales, have followed trajectories which could be characterized by a sequence of straight line segments. We refer to such trajectories as time variant linear trend trajectories. The following examples pertaining to the behavior of the time paths of electricity sales in the U.S. and in Ohio, and of the associated revenues should clarify what we have in mind when we refer to time variant linear trends, or time variant linear trend trajectories. (Exhibit 1)

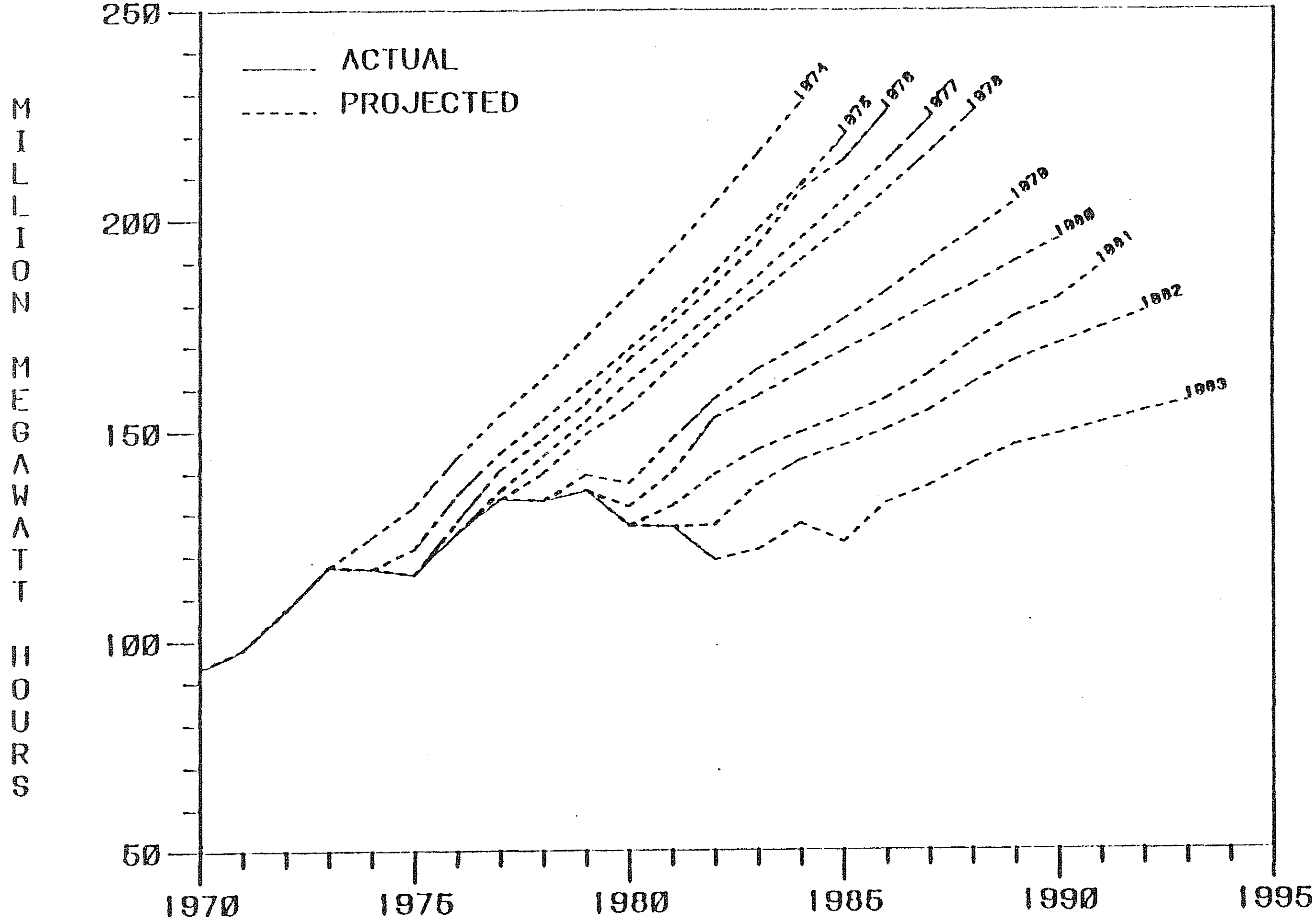
The analysis and assessment of the historical time path trajectories of observed data series is an essential component in projecting their future magnitudes. Traditionally the time path trajectories of economic data series such as those pertaining to the provision and disposition of electricity, have been attempted to be analyzed and assessed through the use of indirect speculative methods such as econometric statistical demand models, or end use demand models. The success of such indirect speculative methods as accurate predictors of future trajectories and even as accurate describers of historical trajectories has increasingly come into question as the realized time path trajectories of electricity sales have consistently diverged from the forecast trajectories.

Figure 1 shows the consolidated ten year forecasts of net electricity generation in Ohio for the decades 1974-1984 through 1983-1993. These forecasts were consolidated from the corresponding Ten Year Forecast Reports of Ohio electric utilities which were submitted annually to the Ohio Power Siting Commission, or to the Ohio Department of Energy, from 1974 to 1982. According to the 1974 ten year forecasts of utilities, the statewide net generation in 1984 was projected to be around 220 billion kWh. The actual 1982 level turned out to be closer to 110 billion kWh.

This kind of discrepancy is one reason why serious doubts have been raised about the reliability of traditional forecasting techniques. Figure 1 shows that the output forecasts of demand models have not been much different from straight line projections of the average trend in the preceding periods of analysis to the next ten years. However, the historical time path shows a discrete decline in the post-1973 marginal trend relative to the pre-1973 trend. Despite such a clear-cut signal given from the data, the demand models have failed to predict that (a) the magnitude of average trends will be declining in the post-1973 period and (b) the forecast trajectory which is projected to move along the average trend will always be above the realized trajectory which follows the marginal trend. The failure of indirect speculative forecasting techniques in these respects suggests a need for developing a new

FIGURE 1.

NET ENERGY DEMAND OF ALL OHIO ELECTRIC UTILITIES



SOURCE 1974 - 1983 TEN YEAR FORECASTS

methodology in analyzing the time paths of economic data series. It is quite clear that direct and deterministic analyses and assessments of the historical trends in many cases could produce by inspection far more accurate, and easy to interpret, results than those produced by various econometric models. We have, therefore, developed a conceptual framework and an analytical metholdolgy for the analysis and assessment of time path trajectories of annual economic data series as a problem in intertemporal measurement of systemic flows. The conceptual framework and the analytical methodology are based upon similar methodologies of measurement and analysis employed in such positive domains of inquiry as astronomy, geodetics and physics and their validity is, therefore, independent of any ontological presumptions which are implicit in current economic analyses and econometric practices.

II. Methodology

A. Conceptual Framework

1. Preliminary Remarks: A time variant linear trend trajectory is a continuous mapping, from the domain of time onto the range of the economic magnitude under observation, which is nondifferentiable at a finite number of points within the time domain under consideration.

From an empirical point of view, the time paths of economic data series may, in general, be regarded as reflecting the dynamic states of economic systems. Where this is the case, discontinuities or nondifferentiabilities in the time path of economic data series would be indications of disruptions or alterations in the historical course of events which have defined the operating conditions of the system in question. Hence, precise, accurate and consistent analyses and assessment of time variant linear trends in the time paths of economic data series would provide useful information in understanding the dynamic behavior and determinants of economic systems.

Whether the measures currently taken to achieve future goals are appropriate or not is contingent upon the validity and accuracy of current analyses and assessments of the projected behaviors of relevant systemic trajectories. Hence, the information derived from analyses and assessments of historical time path trajectories of empirical economic systems may contribute signicantly both to the understanding of positive economic problems and to the design, choice and implementation of suitable measures for their solution.

The accurate and consistent analyses and assessments of time paths require, first of all, an understanding of the general conditions that characterize observed economic data series. Next, it requires a conceptual framework within which observed data can be related to mathematical concepts. Finally, it requires a methodology for the modeling and assessment of the time paths in question, which would represent the functional or definitional relations among the empirical data in terms of mathematical concepts and mathematical functions. We shall briefly address these points in the remainder of this section.

2. The Nature of Economic Data Series: The nature and existence of processes of provision and disposition of a particular commodity in a particular human society are, historical phenomena. The elements of an observed economic data series then reflect the magnitudes of physical or financial transactions that have taken place between the providers and the disposers of

that commodity in that society during successive periods of time. Observations pertaining to the outcomes of such recurrent transactions of a commodity are usually based upon accounting consolidations of measurements on physical or financial flows. The initial data about the levels of production and distribution are measured according to physical models of reality and are compiled and consolidated according to the prevailing accounting theory and practices. For example, sectoral electricity sales are ultimately based upon individual meter readings which are then consolidated according to pervailing accounting conventions.

Every model of data analysis prescribed by an economist must explicitly preserve and consolidate the conditions imposed by the corresponding accounting model which defines the data as well as the physical nature of the observations which the data represent. The neglect of the former may lead to implicit or explicit denial of the basic axiom about the whole being the sum of its parts. The neglect of the latter may lead to postulation of operations which imply adding apples and oranges.

Analyzing the time paths of a related set of economic data series is an exercise in dynamic analysis. For such an analysis to be logically and empirically consistent, it must preserve the static relations that hold among the data at all times. This is a basic principle in positive dynamic analysis. In the case of economic data series, the static relations can, as discussed above, be classified into two general categories: accounting and physical relations.

3. Conceptual Framework for the Interpretation of Time Variant Linear Trend Trajectories: At any point in time there may be many factors which influence the level of transactions of any commodity, such as population, income, prices, costs, employment, technology etc. Each one of these factors may be conceptualized to exert a force on the economic system under consideration with regard to the provision and distribution of a particular commodity X. The rate of transactions of X at any point in time, t, $t_0 \leq t \leq t_0 + n$, can then be conceptualized as a flow velocity the magnitude of which is determined by the initial flow velocity $X_0 = X(t_0)$ plus a series of accelerations resulting from the joint impact of the determining forces operating on the system, described by an acceleration function

1) $$\frac{d\,x(t)}{dt} = f(t)$$

In general then at any point t in an interval of time $t_0 \leq t \leq t_0 + n$

2) $$X(t) = X_0 + \int_{t_0}^{t} f(t)\,dt$$

In the case of a time variant linear trend trajectory we are faced with a situation where the net magnitude of the acceleration produced on the system by the various forces operating on it remains constant within each one of a series of successive subdomains of time, and changes in a discontinuous manner at the turning points between the successive subdomains in question.

Let $Z = < t_o, t_o + n >$ be an interval of size n years, such as January 1, 1960 through December 31, 1982. Let $J = \{t1, t2, \ldots tm\}$ be an m element subset of the set of end points of the annual intervals in Z, with $1 \leq m \leq n-1$, such that every element of J is a turning point in Z, and

$t1 < t2 < \ldots, < tm$.

Let $\ell = 1, 2, \ldots m$.

Let $DUM\ \ell = 0$ if $t \leq t\ell$

$DUM\ \ell = 1$ if $t > t\ell$

Then the acceleration function for a time variant linear trend trajectory would be given by

4) $$f(t) = \sum_{\ell = 1}^{m} a_{\ell} \cdot DUM\ell .$$

We may infer from the behavior of the acceleration function that there must have been significant alterations in the operating conditions of the system under investigation for the configuration of forces which produced constant accelerations in the preceding subinterval of time to be replaced by a new configuration which has produced different net acceleration. The determination or confirmation of the actual changes in the various determinants of f(t) can be carried on through the use of known physical or accounting relations between the time path of the particular determinants and the time path of X(t). However we can always define the behavior of X(t) independently of such determinations.

B. Modeling and Adjustment of a Linear Trend Trajectory: Substituting 4 into 1 we can express the time path trajectory of the annual flows of X as:

5) $$X(t) = X_o + \sum_{\ell = 1}^{m} \{a_{\ell} \cdot DUM\ell \cdot \int_{t\ell}^{t} dt\}$$

or

6) $$X(t) = X_o + \sum_{\ell = 1}^{m} \{a_{\ell} \cdot DUM\ell \cdot (t-t\ell)\}.$$

Let $DUM\ell \cdot (t-t\ell) = T\ell$,

then:

7) $$X(t) = X_o + \sum_{\ell = 1}^{m} a_{\ell}\ T\ell$$

is a linear equation in $m+1 \leq n$ unknowns, the m accelerations a_{ℓ} and X_o, a solution to which can always be found on a case by case basis.

In particular given $n > m + 1$ observations of the form

8) $\{X_t \mid 1, T1, \ldots T\ell\}$

one can express the time path of X_t as

9) $X_t + V_t = X(t)$

and utilize least squares adjustment to estimate parameters mentioned above, under a working hypothesis that the least square residuals

10) $V_t \sim N\{0 \mid \sigma^2 \underset{n\times n}{V}\}$

with rank (V) = n.

III. Modeling and Assessment of Time Variant Linear Trends in Ohio Sectoral Electricity Sales: An Application

A. The Model: Sectoral energy sales in Ohio between 1960 and 1982 can be explained in terms of a sequence of discrete accelerations. The initial accelerations starting from 1960 on remain constant for all sectors through 1966. At the end of 1966 there are positive increments in the accelerations to the residential commercial and transportation sectors which then remain constant through 1972. At the end of 1972 there are declines in the accelerations of residential and commercial sales and an increase in industrial sales. In the case of residential sales there is a further leveling off at the end of 1980.

The industrial sector trends are further characterized by a positive displacement in the trend line after 1971, and negative displacements after 1979 and 1981. The displacements after 1979 and 1981 are clearly associated with 2.5% decline in the unemployment rate in Ohio between 1979 and 1980 and between 1981 and 1982 respectively. An additional variable is utilized in the industrial sector time path to measure the impact of the 1975 recession.

The sectoral sales are measured in trillion Btus. The data are from EEI Statistical Year Book. Adjustment results are reported in Table 1. Data are presented in Table 2.

B. Heuristic Implications-Elasticity of Consumption:

A pressing problem for state regulatory agencies is that of determining the effect of rate hikes on the sales and, hence, on the revenues and profits of the regulated utilities. This is posed, in traditional practice, as a question of price elasticity of demand. A dynamic concept of price elasticity of consumption will be briefly introduced, for it may prove to be more useful and reliable as a tool of positive analysis and as an instrument of policy planning or implementation.

TABLE 1
ADJUSTMENT RESULTS FOR THE COMPONENT TIME PATH MODELS

SYSTEM: SYS2 THIRD STAGE

MODEL: RS
DEP VAR: ELRSBOH

VARIABLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T RATIO	APPROX PROB>|T|
INTERCEPT	1	34.918647	0.655854	53.2415	0.0001
T	1	2.494634	0.159148	15.6750	0.0001
T6	1	2.994792	0.260563	11.4936	0.0001
T12	1	-1.326221	0.214241	-6.1903	0.0001
T20	1	-5.523613	0.622894	-8.8677	0.0001

MODEL: CM
DEP VAR: ELCMBOH

VARIABLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T RATIO	APPROX PROB>|T|
INTERCEPT	1	23.570376	0.863551	27.2947	0.0001
T	1	2.312229	0.207341	11.1518	0.0001
T6	1	2.783961	0.332748	8.3666	0.0001
T12	1	-2.553529	0.244441	-10.4464	0.0001

MODEL: TR
DEP VAR: ELTRBOH

VARIABLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T RATIO	APPROX PROB>|T|
INTERCEPT	1	0.350718	0.014053	24.9560	0.0001
T	1	-0.033985	0.00260966	-13.0229	0.0001
T6	1	0.033985	0.00260966	13.0229	0.0001

MODEL: IN
DEP VAR: ELINBOH

VARIABLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T RATIO	APPROX PROB>|T|
INTERCEPT	1	136.994501	1.910665	71.6999	0.0001
T	1	2.016193	0.282445	7.1384	0.0001
T12	1	3.879750	0.319797	12.1319	0.0001
DUM6	1	24.798590	3.334510	7.4370	0.0001
R82	1	-48.077790	2.194870	-21.9046	0.0001
D75	1	-18.765125	3.973264	-4.7228	0.0002

MODEL: TT
DEP VAR: ELTTBOH

VARIABLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T RATIO	APPROX PROB>|T|
INTERCEPT	1	195.834243	2.159149	90.6997	0.0001
T	1	6.789071	0.397532	17.0781	0.0001
T6	1	5.812738	0.431509	13.4707	0.0001
T20	1	-5.523613	0.660679	-8.3605	0.0001
DUM6	1	24.798590	3.437135	7.2149	0.0001
R82	1	-48.077790	2.262420	-21.2506	0.0001
D75	1	-18.765125	4.095547	-4.5818	0.0003

TABLE 1
ADJUSTMENT RESULTS FOR THE COMPONENT TIME PATH MODELS

SYSTEM: SYS2

THIRD STAGE

COVARIANCE ACROSS MODELS

	RS.ELRSBOH	CM.ELCMBOH	TR.ELTRBOH	IN.ELINBOH	TT.ELTTBOH
RS.ELRSBOH	0.79088487	0	0	0	0
CM.ELCMBOH	0	1.48598590	0	0	0
TR.ELTRBOH	0	0	0.00042536	0	0
IN.ELINBOH	0	0	0	17.83440644	0
TT.ELTTBOH	0	0	0	0	23.99092671

CORRELATION ACROSS MODELS

	RS.ELRSBOH	CM.ELCMBOH	TR.ELTRBOH	IN.ELINBOH	TT.ELTTBOH
RS.ELRSBOH	1.00000000	0	0	0	0
CM.ELCMBOH	0	1.00000000	0	0	0
TR.ELTRBOH	0	0	1.00000000	0	0
IN.ELINBOH	0	0	0	1.00000000	0
TT.ELTTBOH	0	0	0	0	1.00000000

INV CORRELATION ACROSS MODELS

	RS.ELRSBOH	CM.ELCMBOH	TR.ELTRBOH	IN.ELINBOH	TT.ELTTBOH
RS.ELRSBOH	1.00000000	0	0	0	0
CM.ELCMBOH	0	1.00000000	0	0	0
TR.ELTRBOH	0	0	1.00000000	0	0
IN.ELINBOH	0	0	0	1.00000000	0
TT.ELTTBOH	0	0	0	0	1.00000000

INV COVARIANCE ACROSS MODELS

	RS.ELRSBOH	CM.ELCMBOH	TR.ELTRBOH	IN.ELINBOH	TT.ELTTBOH
RS.ELRSBOH	1.26440654	0	0	0	0
CM.ELCMBOH	0	0.67295390	0	0	0
TR.ELTRBOH	0	0	2350.94789654	0	0
IN.ELINBOH	0	0	0	0.05607139	0
TT.ELTTBOH	0	0	0	0	0.04168242

WARNING: DEGREES OF FREEDOM NOT ADJUSTED FOR RESTRICTIONS

WEIGHTED MEAN SQUARE ERROR FOR SYSTEM = 1.189393 WITH 99 DFS

WEIGHTED R-SQUARE FOR SYSTEM = 0.9969
THIS IS THE R-SQUARE THAT CORRESPONDS TO THE APPROXIMATE F TEST ON ALL NON-INTERCEPT PARAMETERS IN THE SYSTEM.

TABLE 2
OBSERVATIONS ON SECTORAL ELECTRICITY CONSUMPTION LEVELS IN OHIO
AND ON THE ASSOCIATED SYSTEM STATE VARIABLES

OBS	YEAR	ELRSBOH	ELCMBOH	ELTRBOH	ELINBOH	ELTTBOH	INT	T	T6	T12	T20	DUM6	D75	R82
1	1960	35.485	24.2593	0.37532	135.286	195.405	1	0	0	0	0	0	0	0
2	1961	37.737	26.5453	0.34120	135.252	199.875	1	1	0	0	0	0	0	0
3	1962	39.818	27.6031	0.27296	141.427	209.121	1	2	0	0	0	0	0	0
4	1963	41.285	29.5820	0.20472	147.603	218.675	1	3	0	0	0	0	0	0
5	1964	44.220	31.1857	0.17060	149.821	225.397	1	4	0	0	0	0	0	0
6	1965	47.666	36.5084	0.17060	143.986	228.331	1	5	0	0	0	0	0	0
7	1966	51.248	39.6474	0.13648	141.666	232.698	1	6	0	0	0	0	0	0
8	1967	54.899	42.2405	0.13648	146.852	244.128	1	7	1	0	0	0	0	0
9	1968	60.085	46.0620	0.17060	155.689	262.007	1	8	2	0	0	0	0	0
10	1969	66.295	50.2246	0.17060	161.865	278.555	1	9	3	0	0	0	0	0
11	1970	72.232	58.7205	0.17060	157.088	288.211	1	10	4	0	0	0	0	0
12	1971	76.702	62.5760	0.17060	161.729	301.177	1	11	5	0	0	0	0	0
13	1972	81.649	67.1140	0.13648	181.655	330.554	1	12	6	0	0	1	0	0
14	1973	88.814	72.8802	0.13648	201.479	363.310	1	13	7	1	0	1	0	0
15	1974	91.169	72.9827	0.13648	196.395	360.682	1	14	8	2	0	1	0	0
16	1975	95.604	76.3605	0.13648	184.487	356.588	1	15	9	3	0	1	1	0
17	1976	98.777	78.8172	0.13648	207.142	384.873	1	16	10	4	0	1	0	0
18	1977	105.874	82.7068	0.13648	223.076	411.794	1	17	11	5	0	1	0	0
19	1978	108.331	82.1609	0.17060	218.436	409.099	1	18	12	6	0	1	0	0
20	1979	110.890	85.3000	0.17000	222.260	418.620	1	19	13	7	0	1	0	0
21	1980	115.450	88.3800	0.14000	185.140	389.110	1	20	14	8	0	1	0	1
22	1981	114.030	90.8500	0.16000	185.930	390.970	1	21	15	9	1	1	0	1
23	1982	113.790	92.5800	0.14000	151.800	358.310	1	22	16	10	2	1	0	2

By definition, at any point in time t,

$$11)\qquad R_x(t) \equiv P_x(t) \cdot X(t)$$

where $R_x(t)$ is the revenues from the sales of $X(t)$, and $P_x(t)$ is the price of X at time t. Hence, if any two of the three elements in the above definition are known over a historical or forecast domain in time, then the third is also known. Differentiating both sides of 11 we get

$$12)\qquad \frac{d\, R_x(t)}{dt} \equiv \frac{dP_x(t)}{dt} \; X(t) + \frac{d\, X(t)}{dt} \cdot P_x(t)$$

or

$$13)\qquad \frac{dR_x(t)/dt}{dP_x(t)/dt} \equiv X(t) + \frac{dX(t)/dt}{dP_x(t)/dt} \cdot P_x(t) \quad , \text{ if } \; d\,P(t)/dt \neq 0,$$

or

$$14)\qquad n = \frac{1}{X(t)} \cdot \frac{dR_x(t)/dt}{dP_x(t)/dt} - 1 \equiv \frac{d\, X(t)/dt}{dP_x(t)/dt} \cdot \frac{P_x(t)}{X(t)} \quad , \text{ if } d\; P(t)/dt \neq 0$$

Hence, as long as the historical time paths of $P(t)$ and $X(t)$ are known, so would $\frac{d\,X(t)}{dt}$ and $\frac{dP_x(t)}{dt}$, so that the right hand side of 14 could be utilized to investigate the historical behavior of the elasticity of disposition of X with regard to price. If this behavior seems to display any regularities over specific subdomains of the historical interval of time under consideration, further research may be conducted to investigate possible determinants of such behavior. Similarly, forecast magnitudes of the elasticity may be computed on the basis of provided scenarios for the projected time paths of $P_x(t)$ and $X(t)$.

The same procedure may easily be extended to explore the nature of dynamic relations between price and consumption, income and consumption, etc.

IV. Conclusion

We have developed a methodology whereby observations on annual economic flow velocities may be characterized in terms of linear time path trajectories that are continuous over a specified domain of time, and are nondifferentiable at a finite number of points in it. The nondifferentiabilities in the time paths are interpreted to reflect the impact of changes in the operating conditions or states of the system due to external or internal shocks, such as OPEC price hikes, recessions, etc., on the dynamic behavior of the system under consideration. The simultaneous assessments of the time path of an aggregate economic flow velocity along with alternative designations of its constitutent components is expected to yield greater insight into the historical determinants of the systemic trajectories under consideration, as well as the dynamic regularities that may be maintained among them. Through continuous monitoring of new observations, such a time path model (a) indicates a likely menu of future system state scenarios, (b) provides a forecast for each specific future scenario in the menu, starting from the most recent state of the system, (c) provides for an early diagnosis of actual alterations in the most recent state of the system, and hence allows for timely updates of the equations of motion, and the forecasts based upon them, (d) allows for integrated analyses of larger and larger numbers of systemic trajectories, connected through definitional or functional relations, so as to both extend the scope of information extracted from the analysis, and to permit forecasts that are consistent with all the available historical information so extracted.

We applied this methodology to the modeling and assessment of the trends in the time paths of sectoral electricity disposition levels in Ohio. The results indicate a decline in the magnitude of annual change in kWh sales in the residential and commercial sectors from 1972 on, with further decline in the residential trend from 1980 on. In the case of industrial sales, the increasing impacts of the fluctuations in general economic conditions are emphasized and quantified. The implications of the identified system dynamics are discussed relative to the construction of reasonable forecast secnarios for the near future. Heuristic implications considered include a discussion of empirical definitions and possible measurement of the concepts of elasticity of disposition, income consumption, and price consumption relations.

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DETERMINING CONFIDENCE INTERVALS
OF LOAD FORECASTS

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Introduction

Forecasting peak loads and outputs are crucial aspects of the planning of electricity production and generating capacity expansion. With every forecast of peak or output, a forecast confidence interval or forecast probability associated with that forecast should be determined. Unfortunately, in practice, forecasts are seldom stated in terms of forecast intervals or multivariate regions. This paper presents formulas for determining forecast intervals and suggests methods by which the formulas may be incorprated into existing forecast methodologies.

Box-Jenkins methodology

Utilities often use the methodology of Box and Jenkins to forecast econometric time series such as peak loads or monthly output. Given a particular time series of peak or output a seasonal ARIMA $(p, d, q)x(P, D, Q)_s$ model may be represented by the backshift polynomials:

$$(1 - \phi_1 B - \phi_2 B^2 - \ldots - \phi_p B^p)(1 - \Gamma_1 B^s - \Gamma_2 B^{2s} - \ldots - \Gamma_p B^{ps})(1-B)^d (1-B^s)^D z_t =$$
$$(1 - \theta_1 B - \theta_2 B^2 - \ldots - \theta_q B^q)(1 - \Delta_1 B^s - \Delta_2 B^{2s} - \ldots - \Delta_Q B^{Qs})\varepsilon_t, \qquad (1)$$

where B is the backshift operator, $Bz_t = z_{t-1}$.

Equation (1) is often written for simplicity in the form:

$$\phi(B)\Gamma(B)_s(1-B)^d(1-B^s)^D z_t = \theta(B)\Delta(B)_s\varepsilon_t \qquad (2)$$

And z_t after differencing, $(1-B)^d(1-B^s)^D z_t = w_t$, so equation (2) simplifies even further to

$$\phi(B)\Gamma(B)_s w_t = \theta(B)\Delta(B)_s\varepsilon_t \qquad (3)$$

For purposes of forecasting and determining confidence intervals of forecasts, the ψ weights of an ARIMA model are especially useful. Essentially, the ψ weights are the coefficients of an ARIMA model when it is re-written as a strictly MA process.

There are two methods of determining the ψ weights: the method of direct substitution, and the method of polynomial division. Both methods are most easily understood by example.

Suppose the appropriate model for monthly peak is a seasonal ARIMA (0, 1, 1)x

$(0, 1, 1)_{12}$. In other words,

$$(1-B)(1-B^{12})z_t = (1 - \theta_1 B)(1 - \Delta_1 B^{12})\varepsilon_t \tag{4}$$

Equation (4) is expanded out to

$$z_t - z_{t-1} - z_{t-12} + z_{t-13} = \varepsilon_t - \theta_1\varepsilon_{t-1} - \Delta_1\varepsilon_{t-12} + \theta_1\Delta_1\varepsilon_{t-13}. \tag{5}$$

Finally,

$$z_t = z_{t-1} + z_{t-12} - z_{t-13} - \theta_1\varepsilon_{t-1} - \Delta_1\varepsilon_{t-12} + \theta_1\Delta_1\varepsilon_{t-13} + \varepsilon_t. \tag{6}$$

Since z_t is given by equation (6), z_{t-1} may be written by using equation (6), shifted back one period. Hence,

$$z_{t-1} = z_{t-2} + z_{t-13} - z_{t-14} - \theta_1\varepsilon_{t-2} - \Delta_1\varepsilon_{t-13} + \theta_1\Delta_1\varepsilon_{t-14}. \tag{7}$$

z_{t-1} of equation (7) is now substituted directly into equation (6). This process is repeated for z_{t-2}, z_{t-12}, z_{t-13}, and so on. Eventually z_t will be re-written in terms of ε_{t-i} $i = 1, 2, 3, 4, 5, \ldots$, as far back as needed by the forecaster. The coefficients of the ε_{t-i} are the ψ weights.

The second method of determining the ψ weights uses the original ARIMA polynomial equation. In this particular example we again use the ARIMA $(0,1,1) \times (0,1,1)_{12}$ equation (4) above.

"Solving" for z_t we have

$$z_t = \frac{(1-\theta_1 B)(1 - \Delta_1 B^{12})}{(1 - B)(1 - B^{12})}\varepsilon_t \tag{8}$$

In general terms, "solving" for z_t as in equation (2) above, yields

$$z_t = [\phi^{-1}(B)\Gamma^{-1}(B)_s(1-B)^{-d}(1-B^s)^{-D}\theta(B)\Delta(B)_s]\varepsilon_t. \tag{9}$$

The coefficients of the polynomial in B are the ψ weights.

$$z_t = (1 + \psi_1 B + \psi_2 B^2 + \psi_3 B^3 + \ldots)\varepsilon_t \tag{10}$$

Or, $$z_t = \varepsilon_t + \psi_1\varepsilon_{t-1} + \psi_2\varepsilon_{t-2} + \psi_3\varepsilon_{t-3} + \ldots \tag{11}$$

A forecast made at time t for ℓ periods ahead, denoted $\hat{z}_t(\ell)$, is the conditional expected value of equation (11) shifted ℓ periods ahead.

$$\hat{z}_t(\ell) = E[z_{t+\ell}] = E[\varepsilon_{t+\ell} + \psi_1\varepsilon_{t+\ell-1} + \psi_2\varepsilon_{t+\ell-2} + \ldots + \psi_k\varepsilon_{t+\ell-k}\ldots] \tag{12}$$

For values of $\ell > k$, the expectation is zero, for values of $\ell < k$, the expectation is simply the historical value of the ε_t. In other words,

$$E(\varepsilon_{t+\ell-k}) = \begin{cases} 0 & \text{if } \ell > k \\ \varepsilon_{t+\ell-k} & \text{if } \ell < k \end{cases}$$

Consequently, $\hat{z}_t(\ell) = \psi_\ell \varepsilon_t + \psi_{\ell+1}\varepsilon_{t-1} + \psi_{\ell+2}\varepsilon_{t-2} + \psi_{\ell+3}\varepsilon_{t-3} + \cdots$ (13)

The error of forecast is the difference between the actual and the forecast, namely

$$e_{t+\ell} = z_{t+\ell} - \hat{z}_t(\ell) \tag{14}$$

$$e_{t+\ell} = \varepsilon_{t+\ell} + \psi_1\varepsilon_{t+\ell-1} + \psi_2\varepsilon_{t+\ell-2} + \cdots + \psi_{\ell-1}\varepsilon_{t+1} \tag{15}$$

The variance of the error of forecast is thus, $\mathrm{Var}(e_{t+\ell}) = E[e_{t+\ell}]^2$. All Box-Jenkins models assume that the random error terms are identically and independently distributed. This means that all squared ε's will have expectation σ_ε^2, and all cross product terms, $\varepsilon_{t+i}\varepsilon_{t+j}$, $i \neq j$, will have expectation zero. Hence, $\mathrm{Var}(e_{t+\ell})$ reduces to a straightforward formula

$$\mathrm{Var}(e_{t+\ell}) = (1 + \psi_1^2 + \psi_2^2 + \cdots + \psi_{\ell-1}^2)\sigma_\varepsilon^2. \tag{16}$$

Thus, the standard error of forecast for a Box-Jenkins model is

$$\sigma_\ell = \sqrt{(1 + \psi_1^2 + \psi_2^2 + \cdots + \psi_{\ell-1}^2)}\ \sigma_\varepsilon. \tag{17}$$

And hence the confidence interval of forecast, ℓ periods ahead is

$$\hat{z}_t(\ell) \pm U_{\frac{\alpha}{2}}\,\sigma_\ell, \tag{18}$$

$$\hat{z}_t(\ell) \pm U_{\frac{\alpha}{2}}\sqrt{(1 + \psi_1^2 + \psi_2^2 + \cdots + \psi_{\ell-1}^2)}\ \sigma_\varepsilon. \tag{19}$$

U denotes the type of distribution of the fitted residuals, and $1 - \alpha$ is the confidence level of the confidence interval.

Regression analysis - single equation

We begin with the standard linear regression model $\underline{y} = X\hat{\underline{\beta}} + \underline{\varepsilon}$, where the vector $\hat{\underline{\beta}}$ of parameters has been estimated by least squares. Specifically, $\underline{y}$ is an N x 1 vector, X is an N x K matrix of exogenous variables, $\hat{\underline{\beta}}$ is a K x 1 vector of estimated coefficients (parameters), and $\underline{\varepsilon}$ is an N x 1 vector of mutually independent disturbances with mean zero and constant variance. The value of the dependent variable for some future forecast period is therefore $y_* = \underline{x}_*\underline{\beta} + \underline{\varepsilon}_*$, where $\underline{x}_*$ is a 1 x K vector of some future value of each exogenous variable.

The forecast of y in the future is $\hat{y}_* = E[y_*] = \underline{x}_*\hat{\underline{\beta}}$, and thus the forecast error is

$$e_{y_*} = \underline{x}_*\hat{\underline{\beta}} - y_* = x_*(\hat{\underline{\beta}} - \underline{\beta}) - \underline{\varepsilon}_* \tag{20}$$

Equation (20) reveals that the error is a result of the sampling error of the least squares coefficient estimator and error of the future disturbances. We are assuming that the elements of $\underline{\varepsilon}_*$ and $\underline{\varepsilon}$ are uncorrelated, and that the estimates of the regression coefficients and of the forecast-period exogenous variables are independent: $E[(\underline{x}_* - \hat{\underline{x}}_*)(\underline{\beta}_* - \hat{\underline{\beta}}_*)] = 0$. See Theil[1971].

The forecast error, equation (20) then has the following variance, denoted

$\sigma^2_{\hat{y}_*}$, $\sigma^2_{\hat{y}_*} = E\,[\,(\underline{x}_*\hat{\underline{\beta}} - y_*)(\underline{x}_*\hat{\underline{\beta}} - y_*)'\,] = \sigma^2_\varepsilon[x_*(X'X)^{-1}x_*' + 1]$ (21)

Equation (21) may be generalized to the variance-covariance matrix of the forecast by substituting X_*, the M x K matrix of the K exogenous variables' values for the M future forecasted periods. I.e.

$$\sigma^2_{\hat{y}_*} = E\,[\,(X_*\hat{\underline{\beta}} - \underline{y}_*)(X_*\hat{\underline{\beta}} - \underline{y}_*)'\,] = \sigma^2_\varepsilon[X_*(X'X)^{-1}\,X_*' + I] \qquad (22)$$

Using matrix algebra, equation (22) is somewhat better understood if slightly re-written.

$$\sigma^2_{\hat{y}_*} = X_*\,[\,\sigma^2_\varepsilon(X'X)^{-1}\,]X_*' \;+\; \sigma^2_\varepsilon I \qquad (23)$$

$\sigma^2_\varepsilon(X'X)^{-1}$ is the variance-covariance matrix of the coefficients $\hat{\underline{\beta}}$, which we denote Ω. Hence equation (23) becomes

$$\sigma^2_{\hat{y}_*} = X_*\Omega X'_* + \sigma^2_\varepsilon I \qquad (24)$$

Equation (24), like equation (20) above, reveals that the variance-covariance matrix of the forecast error is dependent on the sampling error of $\underline{\beta}$, Ω, and the future disturbances, $\sigma^2_\varepsilon I$.

And thus equation (21) may be written as

$$\sigma^2_{\hat{y}_*} = x_*\Omega x_*' + \sigma^2_\varepsilon \qquad (25)$$

An important assumption underlying equations (24) and (25) is that the future values of the explanatory variable are known with certainty, that they are exact. Yet, in many econometric models the independent, explanatory variables are themselves forecasted into the future (say via Box-Jenkins methodology, as above) and thus are stochastic in nature. The forecasted explanatory variables are not known with certainty but, at least, have some variance associated with their forecasted values.

Martin Feldstein [1971] has considered this problem of econometric models when the forecast-period explanatory variables are stochastic, and I will use some of his results in this paper to expand and amend equation (25).

As we distinguish between y_* and $\hat{y}_*$, the actual and the predicted future value of the dependent variable, we shall distinguish between $\underline{x}_*$ and $\hat{\underline{x}}_*$, the actual and the predicted future value of the vector of exogenous variables.

The forecast error is thus

$$e_{y_*} = y_* - \hat{y}_* = (\underline{x}_*\underline{\beta} - \underline{\varepsilon}_*) - (\hat{\underline{x}}_*\hat{\underline{\beta}}).$$
$$= \underline{x}_*\underline{\beta} - \hat{\underline{x}}_*\hat{\underline{\beta}} - \underline{\varepsilon}_* \qquad (26)$$

The variance of the forecast error is

$$\sigma^2_{\hat{y}_*} = E\left[(y_* - \hat{y}_*)^2\right] = E\left[(\underline{x}_*\underline{\beta} - \hat{\underline{x}}_*\hat{\underline{\beta}} - \underline{\varepsilon}_*)^2\right] . \tag{27}$$

Through a series of matrix and expectation manipulations equation (27) reduces to

$$\sigma^2_{y_*} = \hat{\underline{x}}_* \Omega \hat{\underline{x}}'_* + \sigma^2_\varepsilon + \hat{\underline{\beta}}\Sigma\hat{\underline{\beta}}' + \text{trace}\ (\Omega\Sigma),$$

where Σ is the variance-covariance matrix of the estimate, $\hat{\underline{x}}_*$, of $\underline{x}_*$, i.e.

$$\Sigma = E\left[(\underline{x}_* - \hat{\underline{x}}_*)'(\underline{x}_* - \hat{\underline{x}}_*)\right] . \tag{29}$$

Notice that equation (28) is an "expanded" version of equation (25). The first two terms of equation (28) comprise equation (25). The last two terms of equation (28) take into account the stochastic nature of the explanatory variables. Or, put differently, if the explanatory variables were not estimated, but were known, exact constants, then Σ would be identically zero, and equation (28) would reduce to equation (25).

The issue then arises as to how to determine Σ . $\hat{\underline{x}}_*$ is estimated through some forecasting technique, but $\underline{x}_*$ is unknown. Thus, the determination of must, in itself, be estimated. The most direct and logical estimation of Σ is through the use of the variance-covariance matrix of X, the historical values of all explanatory variables. The variance-covariance matrix of X establishes the historical variance of each explanatory variable, $\sigma^2_{x_i}$, and the historical covariance between explanatory variables, $\sigma_{x_i x_j}$.

Correspondingly, the correlation matrix is obtained by dividing each entry of the variance-covariance matrix by the appropriate pair of standard deviations. Or, pre- and post-multiplying the variance-covariance matrix by the standard deviations vector of the explanatory variables yields the correlations matrix.

To estimate Σ we make the following assumption: We assume that the historical correlations between explanatory variables are maintained in the future forecast period. We then construct, year by year, period by period, future variance-covariance matrices that maintain the historical correlation matrix. Each future variance-covariance matrix is the particular Σ for that forecast period. And it is that Σ which is then used in equation (28).

Let us consider the following example to clarify and illustrate this estimate of Σ .

Suppose we have a model using three explanatory variables and no intercept.

$$y = \hat{\beta}_1 x_1 + \hat{\beta}_2 x_2 + \hat{\beta}_3 x_3 + e \tag{30}$$

where σ^2_ε is known from the fitted residuals, Ω is determined through

$$\Omega = \sigma^2_\varepsilon (X'X)^{-1} \tag{31}$$

and $\hat{\underline{\beta}} = \begin{pmatrix} \hat{\beta}_1 \\ \hat{\beta}_2 \\ \hat{\beta}_3 \end{pmatrix}$ is estimated by

$$\hat{\underline{\beta}} = (X'X)^{-1}X'\underline{y} \tag{32}$$

And let us suppose that the historical variance-covariance matrix is

$$\begin{pmatrix} 25 & -2 & 45 \\ -2 & 16 & 3 \\ 45 & 3 & 9 \end{pmatrix}$$

Thus, the historical correlation matrix is

$$\rho = \begin{pmatrix} 1 & -.1 & .3 \\ -.1 & 1 & .25 \\ .3 & .25 & 1 \end{pmatrix}$$

We forecast the explanatory variables for some future period. We obtain the forecasts, $\hat{x}_{1*}$, $\hat{x}_{2*}$, $\hat{x}_{3*}$,

$$\underline{\hat{x}}_* = (\hat{x}_{1*}, \hat{x}_{2*}, \hat{x}_{3*}) \tag{33}$$

We also determine the variances of each forecast. Suppose the variances are

$$\text{Var}(\hat{x}_{1*}) = 1, \quad \text{Var}(\hat{x}_{2*}) = 4, \quad \text{Var}(\hat{x}_{3*}) = 2.25$$

The variances are the diagonal entries of the future variance-covariance matrix Σ .

$$\Sigma = \begin{pmatrix} 1 & \sigma_{x_1x_2} & \sigma_{x_1x_3} \\ \sigma_{x_2x_1} & 4 & \sigma_{x_2\,x_3} \\ \sigma_{x_3x_1} & \sigma_{x_3x_2} & 2.25 \end{pmatrix}$$

The $\sigma_{x_ix_j}$ are then determined so that the corresponding correlation matrix is identical to the historical correlation matrix above, ρ. For example, $\sigma_{x_1x_2}$ must be $-.2$ so that $\rho_{x_1x_2} = -.1$, and $\sigma_{x_1x_3}$ must be .45 so that $\rho_{x_1x_3} = .25$, and so on.

By the pre- and post-multiplication of the appropriate vector, Σ can be determined quickly, and in this example, Σ is

$$\Sigma = \begin{pmatrix} 1 & -.2 & .45 \\ -.2 & 4 & .75 \\ .45 & .75 & 2.25 \end{pmatrix} \tag{34}$$

Now, having all the components of equation (28) in place; viz., equations (31), (32), (33), and (34), we may determine $\sigma^2_{\hat{y}_*}$.

With $\sigma^2_{\hat{y}}$ in hand we must be cautious in its use. The confidence interval of forecast does not follow directly from the determination of $\sigma^2_{\hat{y}}$. Analytically, we do not know the distribution of y_* Even if we assume $\hat{\underline{x}}_*$ and $\hat{\underline{\beta}}_*$ are normally distributed, their product, $y_* = \hat{\underline{x}}_* \underline{\beta}_*$, is not automatically normally distributed. While the confidence intervals cannot be derived analytically, they can be approximated using computer simulation or numerical integration. Through computer simulation the forecast distribution may be approximated, and then the calculated $\sigma^2_{\hat{y}_*}$ may be used.

Feldstein [p.57] suggests the use of the Tchebychev inequality which makes no assumptions about the distribution of y_*

$$P[\ |y_* - \hat{y}_*| > k^2\sigma_{\hat{y}_*}] < \frac{1}{K^2} \tag{35}$$

Inequality (35) should be interpretted as the probability that the actual value y_* will fall outside the interval $\hat{y}_* \pm k\sigma_{\hat{y}_*}$ is less than $1/k^2$.

Regression analysis - complete model

The structural form of a complete model may be written as

$$B\underline{y}_t + \Gamma\underline{x}_t = \underline{\varepsilon}_t \tag{36}$$

where B is a G x G matrix of coefficients (G denoting the number of equations in the model), $\underline{y}_t$ is a G x 1 vector of endogenous, dependent variables, Γ is a G x K matrix of coefficients, $\underline{x}_t$ is a K x 1 vector of explanatory variables, and $\underline{\varepsilon}_t$ is a G x 1 vector of disturbances. The corresponding reduced form equation is

$$\underline{y}_t = -B^{-1}\Gamma\underline{x}_t + B^{-1}\underline{\varepsilon}_t \tag{37}$$

$$\underline{y}_t = \Pi\underline{x}_t + \underline{\nu}_t \tag{38}$$

In this setting we are concerned not only with the forecast error variance of each equation in reduced form, but with the between equation covariance. Hence, a typical element of the variance-covariance matrix of forecast error is denoted, $\sigma_{y_r y_s}$, and is defined by

$$\sigma_{y_r y_s} = \bar{E}\ [(y_{r*} - \hat{y}_{r*})(y_{s*} - \hat{y}_{s*})]\ , \tag{39}$$

where $\bar{E}$ is the asymptotic expectation operator.

Again, through a series of matrix and expectation manipulations, equation (39) reduces to

$$\sigma_{\hat{y}_{r*}\hat{y}_{s*}} = \hat{\underline{x}}_{r*}\ \Omega_{rs}\ \hat{\underline{x}}'_{s*} + \delta_{rs} + \hat{\underline{\beta}}_r\ \Sigma_{rs*}\ \hat{\underline{\beta}}'_s + \text{trace}\ (\ \Omega_{rs}\ \Sigma_{rs*}) \tag{40}\dagger$$

†Equation (40) is essentially identical to equation (10) in Feldstein [p.58]. However, Feldstein's equation has one error; there is a K^2 coefficient preceding the δ_{rs} which should be deleted. I am grateful to Professor Thomas Yancey of the University of Illinois for bringing it to my attention.

In equation (40)

$\hat{\underline{x}}_{r*}$ = the vector of forecasted explanatory variables in the rth equation.

$\hat{\underline{\beta}}_r$ = the estimated parameters of the rth equation.

Ω_{rs} = a block matrix within .

δ_{rs} = covariance of error disturbance between equation r and equation s of the reduced form

Σ_{rs} = a block matrix within .

The block matrix within Ω, Ω_{rs}, is determined in the following way. The row numbers of the block matrix are the r equation's parameters, and the column numbers are the s equation's parameters. This block matrix is found within the variance-covariance matrix of the parameters of the reduced form equations. Analogously, the block matrix Σ_{rs} is found within Σ. See Figure 1 below.

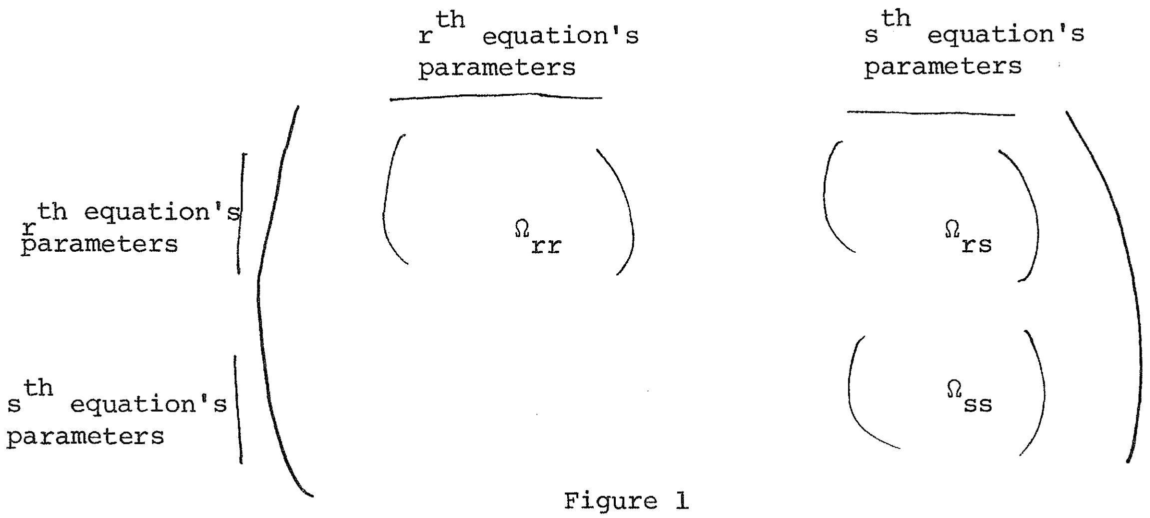

Figure 1

Notice that that block matrices of Ω_{rr} and Ω_{ss} are also illustrated in Figure 1. Using those block matrices the error variance of the rth equation and sth equation can be determined . I.e. $\sigma^2_{\hat{y}_{r*}}$ and $\sigma^2_{\hat{y}_{s*}}$ can be determined using Ω_{rr}, Σ_{rr}, and Ω_{ss}, Σ_{ss}, respectively.

Notice also that when determining $\sigma^2_{\hat{y}_{r*}}$ and $\sigma^2_{\hat{y}_{s*}}$ equation (40) reduces to equation (28).

With more than one equation in the model there are no longer one-dimensional forecast intervals, rather multidimensional forecast regions. Feldstein and others refer to Hooper and Zellner's [1961] definition of multidimensional forecast regions based on Hotelling's T^2 statistic. The Hooper and Zellner multidimensional forecast regions require, among other things, that the explanatory variables be known constants. Since we are dealing with stochastic explanatory variables, Feldstein suggests the multidimensional analogue of the Tchebychev inequality as a conservative approximation of multidimensional confidence regions.

$$P\left[\sum_r \sum_s \sigma^{rs}(y_r - \hat{y}_r)(y_s - \hat{y}_s) > K^2\right] \leq \frac{G}{K^2} \tag{41}$$

where σ^{rs} is the r,s-entry of the inverse of the forecast variance-covariance. The matrix whose construction was discussed above in equations (39) and (40).

For pairs of equations in the reduced form, the multidimensional region is an ellipse, for three equations the region is an ellipsoid, etc.

Stochastic simulation

Another method by which forecast distributions and confidence intervals may be determined is through stochastic (computer) simulation. This is done by specifying a particular model, specifying a probability distribution for the error terms and for each estimated coefficient. Next, a large number of simulations are performed having the computer draw (Monte Carlo fashion) values from the specified distributions. That is, in each simulation values for the additive error terms and the estimated coefficients are chosen at random from the corresponding probability distribution.

For any particular dependent variable, the results of the simulation produce values that empirically describe the probability distribution of that variable's forecasted value. Thus, the dispersion of the forecasts about their mean be used to define a forecast confidence interval.

For example, with the ARIMA (0, 1, 1) x (0, 1, 1) $_{12}$ discussed above

$$z_t = z_{t-1} + z_{t-12} - z_{t-13} - \hat{\theta}_1 \varepsilon_{t-1} - \hat{\Delta}_1 \varepsilon_{t-12} + \hat{\theta}_1 \hat{\Delta}_1 \varepsilon_{t-13} \qquad (6)$$

where $\varepsilon_t \sim N(0,\sigma_\varepsilon^2)$, $\theta_1 \sim N(\hat{\theta}_1,\sigma_\theta^2)$, and $\Delta_1 \sim N(\hat{\Delta}_1,\sigma_\Delta^2)$, simulation means choosing values for each coefficient and the additive term from their respective distributions. These values are used for z_{t+1}. To determine z_{t+2}, z_{t+3}, ... we recursively substitute z_{t+1}, z_{t+2}, z_{t+3}, while holding θ_1 and Δ_1 fixed. A new value for ε_{t+i} is chosen at each stage from $N(0,\sigma_\varepsilon^2)$ See the equations below illustrating this process.

$$\text{If, } z_{t+1} = z_t + z_{t-11} - z_{t-12} - \hat{\theta}_1 \varepsilon_t - \hat{\Delta}_1 \varepsilon_{t-11} + \hat{\theta}_1 \hat{\Delta}_1 \varepsilon_{t-12} + \varepsilon_{t+1}$$

$$\text{then, } z_{t+2} = z_{t+1} + z_{t-10} - z_{t-11} - \hat{\theta}_1 \varepsilon_{t+1} - \hat{\Delta}_1 \varepsilon_{t-10} + \hat{\theta}_1 \hat{\Delta}_1 \varepsilon_{t-11} + \varepsilon_{t+2}$$

and so on.

new chosen value

After t+1, t+2, ..., t+ℓ steps ahead of simulation, new values of θ_1 and Δ_1 are chosen from their distributions and the ℓ steps of simulation are repeated. After a sufficiently large number of simulations are taken, the forecast distribution and confidence intervals can be empirically determined.

Simulating regression models is quite similar to the above simulation. Assuming unbiased and consistent estimates have been calculated for the regression equation(s) coefficients, the probability distributions of the coefficients and error terms result from the distribution. So, for example, if a regression model of peak load is of the form

$$y = \hat{\beta}_0 + \hat{\beta}_1 x_1 + \hat{\beta}_2 x_2 + \varepsilon$$

with $\hat{\beta}_0 \sim N(\hat{\beta}_0, \sigma^2_{\hat{\beta}_0})$, $\hat{\beta}_1 \sim N(\hat{\beta}_1, \sigma^2_{\hat{\beta}_1})$, $\hat{\beta}_2 \sim N(\hat{\beta}_2, \sigma^2_{\hat{\beta}_2})$, $\varepsilon \sim N(0, \sigma^2_{\varepsilon})$.

Then x_1 and x_2 are forecasted for some future period, and $\hat{x}_{1*}$ and $\hat{x}_{2*}$ have some forecast period distribution, say a normal distribution. Then a large number of simulations are performed having the computer draw (Monte Carlo fashion) values from the specified distributions -- in this case, values are drawn for the coefficients, the error term, and the explanatory variables.

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LOAD FORECASTING AND GENERATING CAPACITY EXPANSION
THE ALGERIAN EXPERIENCE - METHODS USED AND RESULTS

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This last decade has been one of confusion for planners and forecasters in electricity who have raised doubts about the methods used.

In developed countries it was the end of the "exponential" and econometric models which had been so much used and corroborated by economic growth that they had obtained the status of "laws".

In developing countries it was the explosion of the myth of the constant or universal "non-variant" which, once determined, would predict our own progress on the basis of the background of the more advanced countries.

The most outstanding effect of this questioning is the renewed interest of planners in the energy forecasting methods based on an analytical approach (extrapolation methods and econometric models having been retrospectively disqualified by the upset of the world energy market). New prospective approaches have also been worked out based on the scenario method. In opposition, during the sixties and seventies, almost all efforts were devoted to load curve forecasting.

The experience of the SOCIETE NATIONALE DE L'ELECTRICITE ET DU GAZ (SONELGAZ) will be described in the context of this renewal of methodology with special attention being paid to the specific problems of developing countries.

1. Forecasting Methods

Two kinds of planning studies are performed at Sonelgaz :

- long term studies (every three years) : two or three scenarios for the development of the electricity sector over the next 20 or 30 years are examined ;

- medium term studies (every year) : with a view to equipment decisions for the next seven to ten years.

1.1. Electrical Energy Forecasts

For medium term studies SONELGAZ has always prefered the so-called "analytical" or "sectorial" method where :

- Power consumption is broken down into the major economic sectors ;
- projects within each sector are considered so as to evaluate growth of the sector over the study period ;
- overall consumption is then estimated year by year.

Econometric methods were also used, but rather for the intellectual satisfaction of manipulating equations and computing means, standard deviations and confidence intervals at 95 and 99 %.

An evaluation of the forecasting methods and a comparison of objectives with actual consumption figures a posteriori confirmed the rightness of choosing the analytical method. The differences between forecasting and reality were two to four times smaller with this method than with econometric methods.

But for the long term, even the analytical method taking account of future projects fell through as economic projections for 20 or 30 years do not exist. Our first studies therefore used mainly analogical methods.

These methods presuppose that some more advanced countries, chosen for their similarities with Algeria (climate, type of development, etc) have followed the same path, and that by observing their position and growth rate we can "predict" the same things for our country 20 or 30 years hence. This reasoning was used both overall (by referring to per capita consumption) (1) and for individual sectors (industry, agriculture, services, etc). (2)

The limitations of these methods were already known in spite of the fascination for a mode of development which nothing seemed able to call in question. We therefore always considered two or three contrasting variants so as to cover the range of future situations.

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(1) The AOKI method developed by IAEA in 1974 is an excellent illustration of this method.

(2) UNIPEDE : International manual on medium and long term electricity consumption forecasting methods - Paris - 1972.

For two or three years now, following a study performed jointly with the International Atomic Energy Agency, these forecasts are calculated using a simulation model (Model for Analysis of Energy Demand : MAED) which links the demand of useful and/or final energy with its major socio-economic and technical determinants and thus helps to predict the evolution of the electricity sector within the energy sector.

Nevertheless, the qualitative contribution of recent years should be associated, not with the use of what is in fact a very simple mathematical tool, but mainly with the philosophy of the method which obliges the electricity forecaster to spell out all the assumptions determining a proposed consumption objective.

1.2. Load Forecasting

Load forecasting, i.e. transformation of energy objectives to the load needed by the grid, has grown through three phases corresponding to a growing mastery of methodology and above all to the availability of data.

During the early period, when investment was rather low and occasional only, forecasts were made without using any model. It consisted only in forecasting peak and base load with reference to an improvement of the load factor and for the ratio of peak to base load. From time to time, consumption data were examined to find the trend of seasonal,weekly and daily variations in load. By extrapolation, a forecast of load curves and load duration curves could be obtained.

In the second period a data file of half-hourly loads was set up so that it was possible to use extrapolation models. The method was exactly the same as that used for the previous manually computed forecasts but these models improved the quality of results because with automatic computer it was possible to use all available data in an exhaustive and complete analysis.

Extrapolation models based on the approximation of the load duration curves by polynomial curves were also tested when the first studies were made with WASP, but they were never used for planning studies because the distortion of the peak and base of the load duration curve, due to the polynomial representation, were felt to be too large.

It may be noted that second period coincided with the introduction of mathematical models for capacity expansion planning studies.

During the third period, industrial consumers were investigated and a detailed analysis of domestic load curves was performed, which enabled sectorial models to be introduced, based on :

- A breakdown of consumers into "sectors", i.e. into sets bearing the same features of modulation :
- determination of the modulation coefficients (seasonal, weekly and daily) for each sector which enable the hourly sectorial load to be deduced from the yearly energy ;
- reconstitution of the annual load curve by adding together the sectorial load curves.

2. Generating Capacity Expansion

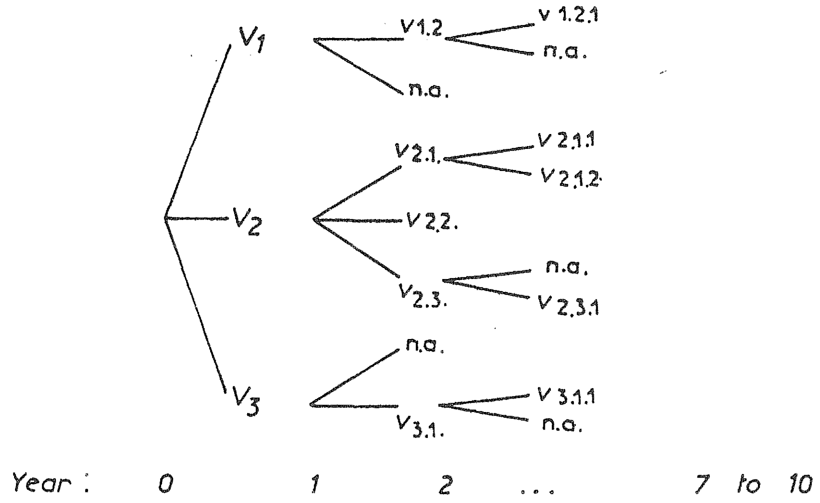
Like all developing countries, Algeria went through a period of economic problems after Independence. This was a time of stagnation or very low growth in electricity consumption. As investments were only small and occasional, planning was easily carried out without any need for automatic computers and models.

In the early seventies, with the recovery of economic growth, it became necessary to define more rigorous planning procedures using mathematical models, mostly obtained from consultants.

2.1. Annual Simulation Models

For several years the capacity expansion studies were performed with a simulation model (REVMAC : Révision des Machines). This model simulates annual operation of a given power system taking into account the characteristics of power units and the demand to meet (represented by weekly load duration curves). Its main aim is to define a maintenance program but it also computes some characteristics which help to decide whether the power system is adequate for the demand : probable production of each unit and corresponding costs, probable number of short supply hours and unserved energy.

The power system was sized using an iterative procedure :



A solution V is not acceptable if it does not satisfy the previously chosen failure criterion or if its cost is much higher than the others.

This method enabled the best of the tested variants to be identified but without any insurance that it was the optimal one. Moreover, it was very expensive. Some studies required the program to be run on the computer 400 times.

As from 1975, there was therefore a growing interest in capacity expansion optimisation models.

2.2. Power System Optimisation Models

We began to write the first model in 1973/74. It was named DORA (Développement Optimal du Réseau Algérien). It can define the optimal policy for developing the power system and the transmission grid for a 20/25 year period, by minimising an objective function under constraints, using the linear programming method. The study period is divided into three part :

- One period of planning (4/5 years) ;
- one period for prospective planning (4/5 years);
- the final ten years, enabling the link to be made with the distant future.

As further results it gives the optimal operating mode of the production units during the period and the ability of the power system to satisfy demand, even when one considers the uncertainty of consumption and when one simulates deficiencies in production (e.g. failure of one production unit and one transmission ligne, or of two production units).

This model was not much used because of the time needed to organise and prepare the date to be introduced into the LP package and to read the results correctly. Since 1981 a new improvement has been added, consisting of two interfaces, before the package and after, to facilitate its utilisation.

From 1978, the studies performed with the assistance of consultants and IAEA on the possibility of introducing nuclear power plants in the Algerian power system have given Sonelgaz the opportunity of obtaining two other models : MNIA (Modèle National d'Investissement - Algérie) and WASP (Wien Automatic System Planning Package).

The two models are very well known and have no need to be described in this paper.

- MNIA is a simplified version, adapted to Algeria, of the Electricité de France MNI model. Its method is optimal control, in the sense of L. Pontryaguine, in order to optimise the power system (continuously, not unit by unit). (1)

- WASP has also been adapted to developing countries from the model of the Tennessee Valley Authority (TVA). The optimal solution is obtained there by the dynamic programming method. (2)

It may be noted that the WASP model (II and III) has been the most used one up till now. Indeed, some of its aspects are more practical (modular structure, consideration of the power in a discrete rather than continuous form, etc), and above all, it is much better known through the IAEA training courses, attended by several Sonelgaz engineers.

3. First Elements for a Comparison between WASP and MNIA

We should first comment that these elements are for comparison and are not an evaluation of the models. They are only the first results of a long job started in Sonelgaz in order to obtain better knowledge of the available models and how well they adapt to the characteristics and operating methods of the Algerian power system. While these models are well known globally speaking (methodology, utilisation), a lot of aspects need to be studied in the field of modelisation.

The first step was to take one scenario (the medium one) from the study performed jointly by IAEA and Sonelgaz (2) and to study it with MNIA.

The first results obtained were rather different from those obtained with the WASP model.

The global capacity installed computed by the two models is equivalent, but the proportions of the different types of equipment is very different as is shown in the following table.

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(1) A. Breton and F. Falgarone : Application de la théorie de la commande optimale au choix des équipements à Electricité de France. (Fourth PSCC - Grenoble - Sep. 1972).

(2) cf. P.E. Molina : Long Term Forecasting of Electric load within Overall energy demand : use of combined MAED and WASP Methodology.

Year	Nuclear		Steam turbines		Gas turbines	
	WASP	MNIA	WASP	MNIA	WASP	MNIA
1986	0	0	58 %	58 %	42 %	42 %
1994	0	0	68 %	31 %	32 %	69 %
1995	0	0	66 %	44 %	34 %	56 %
2000	0	15 %	62 %	42 %	38 %	43 %
2008	0	46 %	71 %	26 %	29 %	28 %
2016	0	53 %	73 %	18 %	27 %	29 %

The data introduced in the two models are not identical but the very slight differences cannot account on their own for the discrepancies between the two optimal solutions obtained using nearly equivalent criteria of reliability.

At this stage we can only put forward hypotheses and not provide explanations. But research is continuing with closer examination of differences in modelisation (simulation of operation to start with, calculation of failure rate, accounting for residual value of equipement at the end of the period).

3. Conclusion

In ten years, Sonelgaz has managed to set up procedures and methods for forecasting and development of production capacity.

This experience, started off with very small ressources (2 or 3 engineers), and using qualified consultants, has been achieved pragmatically by obtaining the necessary models (sometimes more than necessary !) and adapting them to the particular conditions of the grid and the data available.

The first lesson it taught us was that we should resist (not always easy !) two temptations in the use of forecasting and planning models : greed for more models and belief in their infallibility.

- Models and methods cannot make up for lack of or poor data. In general, the more models there are and the more they become sophisticated, the more data is required to get good quality results.

- An "optimal solution" is always the result of constraints, explicit of implicit assumptions and simplification of the system for modelisation purposes. Models never release the planner from his responsibility. They are useful tools, considering the size and complexity of electrical systems, but they should never be divorced from a critical sense.

This is all the more true in developing countries, where programs are often imported and the accepted modelisation is not always suitable for small grids (e.g. in considering equipment reliability).

ANNEX

SHORT PRESENTATION OF THE ELECTRIC SECTOR IN ALGERIA

Generation, transmission and distribution of electricity in Algeria is the responsability of "LA SOCIETE NATIONALE D'ELECTRICITE ET DU GAZ" (SONELGAZ), a state owned company.

At present, the company has an interconnected system covering the north of the country and more than 80 isolated generation stations in the south : 5 big gaz turbine plants and the others are small diesel plants.

The interconnected system operates at 220 kv transmission voltage and distribution to the substations and to the consumption centers is through 63 kv lines. Further distribution is mainly by 33 kv lines and to a lesser extent by 11 kv lines.

In the next table are given some data about the production and the annual peak load.

	1969	1973	1977	1982
National Production (GWh)	1770	2682	4411	9326
Production of the interconnected system (GWh)	1418	2180	3668	7052
Peak load on the interconnected system (MW)	284.5	446.5	726.4	1305.7

INTEGRATED UTILITY PLANNING AND CONSUMER RESPONSE MODEL

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1. Introduction

The changes in demand and uncertainties in the economy has made the regulation of electric utilities a very complicated issue. Already over-burdened staffs are faced with yet more numerous, more difficult cases. What is the most troubling is that the "old tools" just do not seem to work under the current conditions. How should load management/conservation mandates be implemented and judged? How can the large uncertainties in inflation, demand growth and energy costs be dealt with adequately?

The Advanced Modeling/Simulation Group of the Control Data Corporation and the Economics Group of Los Alamos National Laboratory anticipated these problems and developed an integrated utility and consumer response model to meet today's needs. The models are designed for planning/policy analysis. They are placed in the public domain, even though they were produced with private funds, to encourage their use. They are already being used by numerous utilities and utility commissions domestically and abroad.(1) The purpose of the models is to allows analysts and policy makers to resolve more issues more quickly and more comprehensively. This feat is accomplished by using causal/dynamic modeling techniques and focusing on closing the feedback loops which describe the interaction between the utility, the commission, and the service area. An EPRI sponsored case study comparison of a dozen strategic planning models by U.S. electric utility company planners agreed that future model developments should attempt to close these loops in a dynamic model.(2) In a later LANL workshop on utility regulatory/ financial modeling, model builders and model users agreed that the explicit representation of feedback was especially important.(3) The closing of these loops has only been accomplished through the application of causal modeling using the system dynamics technique discussed here.

A causal model is simply a description of what causes what. Consequently it is humanly easy to understand. It requires little data because the data is generated internally just as the relationship in the real world cause the consequences recorded as "data" in other models. From a computerization perspective, this also means the models are extremely fast and easy to use. From a conceptual perspective, it requires the model builder and user to view the "world" as an integrated entity. The model must be comprehensive and describe how the relationship in the utility and its environment feedback on one another. As a reward for this effort, the models can describe history given only the conditions in, for example, 1950. Given that the model can describe history without time series data, there is much more confidence that the model can properly address as yet unknown problems and policies in the future.

2. Feedback

Figure 1 shows some key feedback loops associated with the regulatory/construction/consumer portion of the model. This diagram shows model variables interconnected by lines of causal influence. The signs at the end of each arrow represent the polarity of effect. For example, Figure 1 shows that an increase in the actual price of electricity causes a decrease in the demand for electricity in the future.

A decline in the demand for electricity causes an increase in the indicated price of electricity that the utility must charge if it is to earn the allowed revenues. This, in turn, would cause the actual price of electricity to increase after a delay required for the regulatory body to complete hearings. The positive feedback loop can work in the opposite direction if an initial decline in the electricity price is followed by increased consumer demand and an opportunity for the utility to lower rates still further while still covering its fixed costs.

Regardless of whether they work towards rapid growth or rapid decline, such closed chains of causal influence are called positive feedback loops. This is the "demand spiral loop". It has two important delays that slow the action of the loop: the regulatory lag required for the state commission to alter rates; and the consumer lag in altering electricity consumption in response to a change in the price of electricity.

Figure 1 also shows an important loop describing the utility company's response to change in the demand for electricity. If demand increases, the company's forecast of future capacity requirements would increase, and the company would initiate preconstruction planning on new units. After delays for planning and construction, these units would come on line and equate installed capacity with the utility's estimated requirements. This loop, the "Construction Loop", brings utility generating capacity into balance with consumer demand. There is no guarantee, however, that this loop can maintain this balance because its actions are slowed substantially by the long delays required for planning and construction.

The demand spiral loop and the construction loop are interconnected as utility planners and electricity consumers act over time to change the status of the system. This interaction is portrayed in Figure 1 as the three combined feedback loops at work in the simulation model. A new feedback loop appears when one traces the causal influences around the outside of the diagram.

If the demand for electricity were to increase, there would be an increase in the company's forecast and in the initiation of planning for capacity additions. After a delay for preconstruction planning and the delay for plant construction, the new units would come on line and enter the company rate base. This would increase the company's allowed revenues and the price of electricity that must be charged under the rules of the commission. After a regulatory delay, the actual price of electricity increase causes a decline in the demand for electricity.

If the demand drops too drastically, the utility is left with underutilized capacity. It must then go to the commission for rate relief to cover the "excess" fixed cost with the existing reduced demand. The new higher prices cause further decline in demand and a "spiral" of price growth is generated.

Note that the model variables and interconnecitons shown in Figure 1 are only a subset of those included in the electric utility simulation model. Indeed, a complete picture of the total model would include hundreds of feedback loops; only the three most important loops for our investigation are shown in Figure 1.

Figure 2 shows an overview of the model. Again, the arrows show the causal information links between components. The flow of information is continuous and dynamic. All the important interactions affecting the utility must be included if a useful understanding of the future and policy impacts is to be obtained. The initial work on the utility portion of the model was performed at LANL(1). The demand component was developed, throughout, by CDC staff(4).

3. Utility Sectors

The utility portion of the model, at on aggregate level, describes all the major considerations of the entire integrated utility. Any variable in the model is available in either tabular or graphical form during an interactive computer session. Policies are also changed interactively. The results are available for any and all points in time. Table 1 shows examples of the output often requested from the model for each sector. This tabulation also illustrates the comprehensive capabilities of the model.

Table 1. Utility Model Output Capabilities

Regulatory:	Allowed Rate of Return, Sector Specific Prices, Rate Base, Deferred Earnings AFUDC/CWIP Impacts, Allowed Revenue, Allowed Expenses, Fuel Adjustment, Regulatory Lag.
Finance:	New Plant Financing, New Debt, New Common Stock Shares, New Preferred Stock, Stock Price, Intermediate Debt, Interest Payment, Dividends, Depreciation, Rate of Return, Taxes, Balance Sheet, Income Statement, Source/Use of Funds.
Production Sector:	Plant Dispatch (arbitrary number of plant types) Power Interchange, Purchase Power.
Capacity Planning:	Forecasted Load Duration Curve, New Plant Planning, New Plant Construction, Construction Delays, Plant Cancellations, Choice of New Plant Type.
Generation:	Construction Costs, AFUDC, CWIP, Plant Retirements, Operating/Maintenance Costs, Efficiency, Fuel Costs, T&D, Arbitrary Number of Plant Types.

The regulatory sector of the model can inherently consider a wide variety of regulatory policies and options. More importantly, the regulatory sector (or any sector) can be readily modified to consider any policy.

The finance sector not only generates all the important financial statements, it acts as a real utility finance department. It follows policies for obtaining new funds. It seeks whatever debt or equity is needed to satisfy its needs. If it has excess funds, it may buy back intermediate debt or common stock or it may make short term investments or diversify. Cash flows are explicity modeled as are the decisions which affect them.

The production sector uses a derating method to dispatch plants. It purchases power when desired or necessary. The capacity expansion sector decides when new plants are needed based on its perception of demand growth. If that perception is later proved incorrect, the plant is delayed or even cancelled -- just like its real world counterpart does.

In the generation sector, the physical plants (by type) are built, operated and retired. The actual physical and financial flows associated with each plant type is explicitly simulated.

For illustrative purposes, typical selected model results for base and low demand growth are shown in Figures 3 and 4.

4. Demand Sectors

The demand sector is also causal. It contains no elasticities as is common to other modeling methods. In the demand sectors, energy use changes because of new investments in efficient technologies, retrofitting activity, budget constraints, capital stock utilization, fuel switching, cogeneration, retirement of older buildings/equipment, and others. The capabilities of the demand sector are summarized in Table 2 below.

In the model, the demand for energy is considered the same as any goods or service in the economy. It is required in varying quantities to produce output. The amount of energy demand depends on the amount of goods produced and quantity needed per unit. The output produced is a function of productive capital (plants, factories, stores, homes, machines, etc.) and capital utilization. Capital is accumulated by investments.

Energy demand is multifaceted. There are substantial demands for which any fuel can be used such as for boilers and space heating. There are non-substitutable demands for which only one fuel can be used. For example, electro-mechanical and lighting uses of energy can be satisfied by electricity alone.

There are also two efficiency components to the demand for energy. There is a process efficiency which states how many BTUs of usable energy are required per unit of output. Usable energy could mean the output heat of a furnace or steam from a boiler. There is a thermal efficiency which states how much input fuel is required to get the required usable energy. As fuel costs rise, the thermal efficiency should increase as more efficient and costly furnaces are installed. Likewise, high fuel and capital costs (and operating costs) lead to a higher cost of using energy. Thus, the process efficiency should also increase and process capital made more energy efficient. (For example by adding insulation or heat exchangers.)

Table 2
DEMAND Sector Capabilities

Load Duration Curve by sector, function, age class, and fuel at all points in time.

Sectors:	Residential, Commercial, Industrial (arbitrary number of industrial sectors), Power Pool (firm and non-firm demand), Municipal (firm and non-firm demand).
Function:	Process (Industrial only), Heating, Cooling, Electromotive (Lighting, Appliances, etc.).
Age Class:	New, Middle, Old.
Fuel:	Conventional Electric, Heat Pump, Alternative Fuel (arbitrary number of alternatives).
Load Duration:	Semi Annual (Winter/Spring, Summer/Fall).

The previously mentioned budget constraint is the fuel-specific capacity utilization representing the short-term response of an energy user to rising energy prices. This response takes the form of a budget constraint which limits how much a user can afford to pay for energy in the short-term and what temporary energy saving actions can be taken (i.e., turn down the thermostat and close off unused rooms). The overall structure of demand is shown in Figure 5.

There is a trade-off between efficiency and capital costs, as depicted in Figure 6. Technology sets an upper limit of efficiency at any cost. Further research and development efforts can move this technical limit upward until theoretical thermal efficiencies are reached. In theory, at the margin, the position on the efficiency/cost curves for new investments (equipment) is determined by balancing capital and operating costs against efficiency and fuel costs. This balance minimizes the cost of using energy.

Investment in each type of capital stock are allocated according to the cost of using each type of energy. This cost is the perceived cost to the user. It includes risk, the annualized capital costs, operating costs, delivered marginal fuel costs and any indirect costs (such as perceived social costs or indirect use costs).

Not all investment funds go to the least expensive energy form. Uncertainty, regional variations and limited knowledge make the perceived price a distribution. The investments going to any fuel type are then proportional to the fraction of times one fuel is perceived as less expensive than all others. This is illustrated in Figure 7.

The demand sector describes both the short-term and long-term impacts of regulatory or utility policies. These impacts, in turn, affect the utility and often lead to further regulatory intervention. Therefore, the integrated utility model is especially valuable for the analysis of policies before they are implemented.

The integrated model generates results that are often "missed" by other approaches. The model indicates that many conservation programs reduce the utility load factor because they affect the base load more than the peak demand. Further, much of the proposed conservation legislation, leads to increased costs for the non-participants in the conservation program. Real "no-loser's" legislation is usually not cost effective.

Finally, the efficiency curves in Figure 6, imply that after some price level, additional price increases can cause only minimal additional conservation. Therefore, load management/conservation is a finite resource. Once it is used up, energy demand is in lock stop with economic output. Both the utility and the consumer will lose any flexibility they have in responding to energy price changes.

5. Conclusion

The integrated utility model is an important tool in todays regulatory environment. The model described here satisfies the need to analyze a wide variety of policies/scenarios in a fast, self consistent manner. Subsidies, rate schedules, taxation, conservation, load management, rate base additions, and many other policies can be easily tested.

Current contracts that use the integrated model will lead to the development of macroeconomic and utility diversification sectors. The macroeconomic sector will allow analysts to determine the impact of policies on industrial competitiveness and possible migration. The subsequent impacts on commercial activity and labor (residential sector) will also be simulated.

As the few remaining generating stations under construction are brought on line, the utilities will have strongly positive cash flows and little need for "utility" investment funds. In their efforts to use the cash efficiently, several regulatory-related concerns will need to be simulated. The integrated model can evolve, as necessary, to serve those needs.

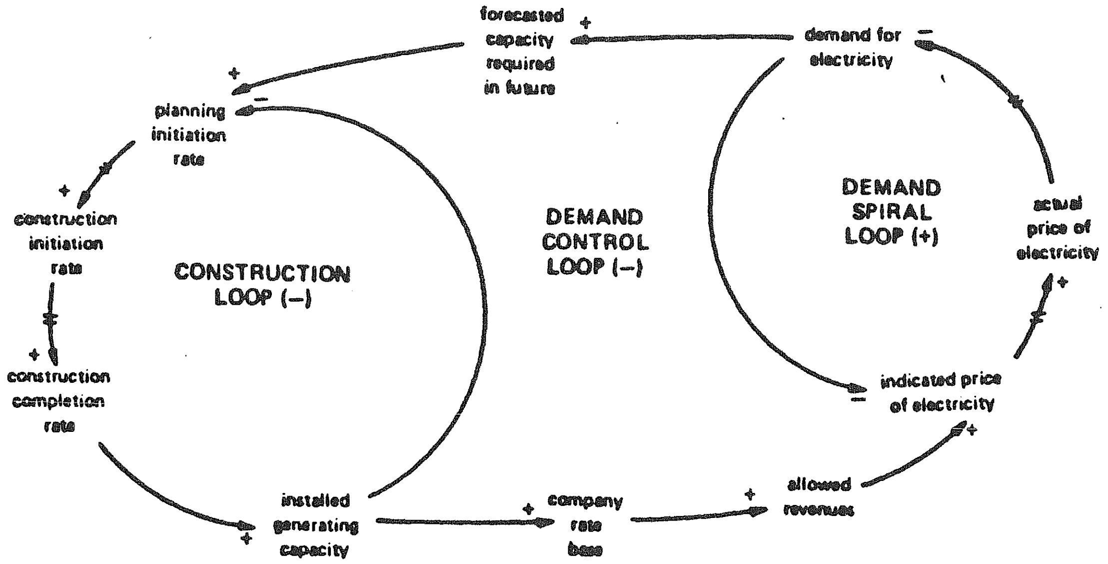

FIGURE 1. CAUSAL DIAGRAM OF KEY LOOPS IN THE UTILITY/REGULATORY/CONSUMER SYSTEM

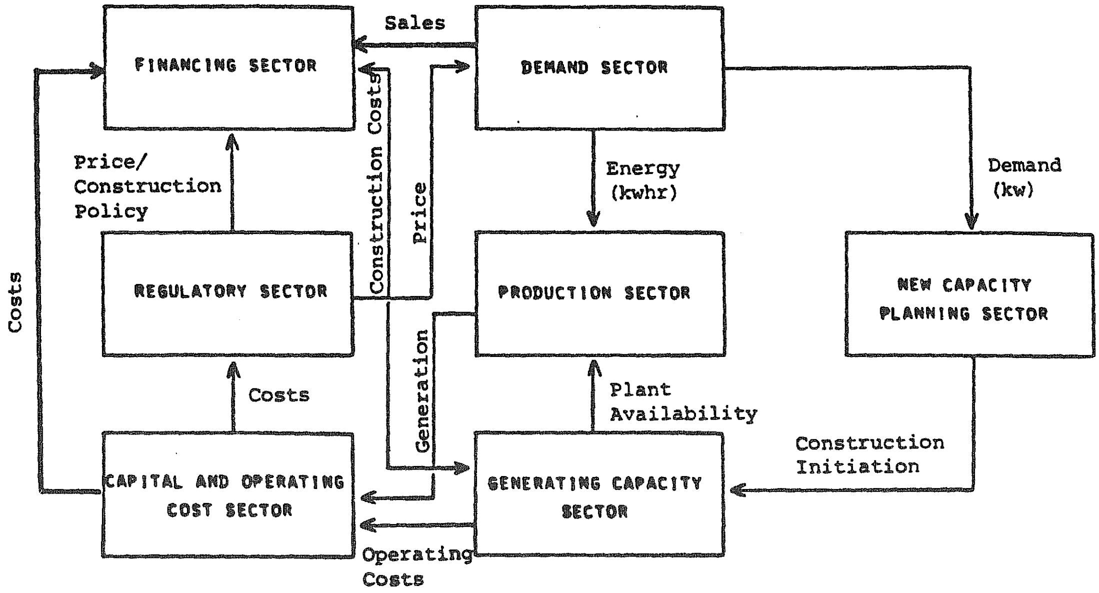

FIGURE 2. MODEL OVERVIEW

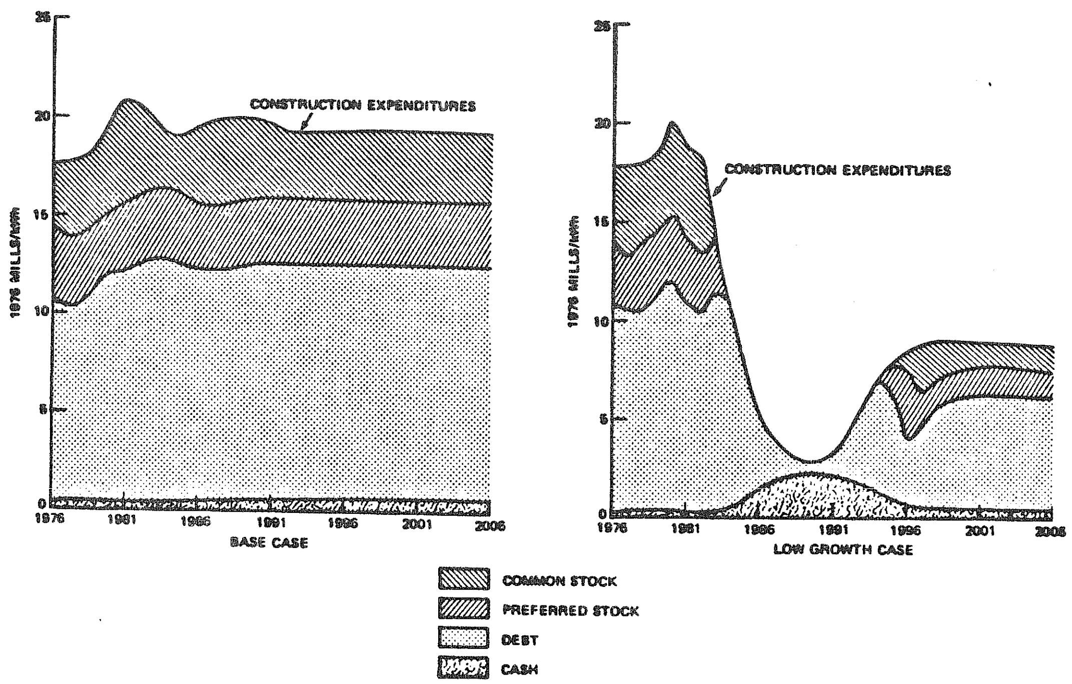

FIGURE 3. SOURCES OF FINANCING

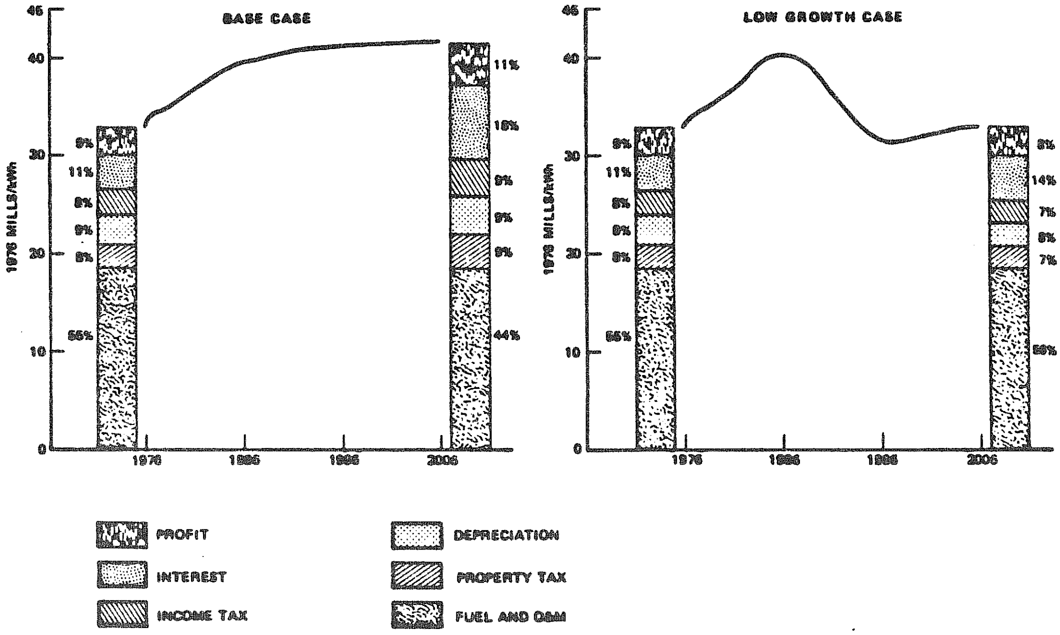

FIGURE 4. EFFECT OF GROWTH ON COMPONENTS OF PRICE

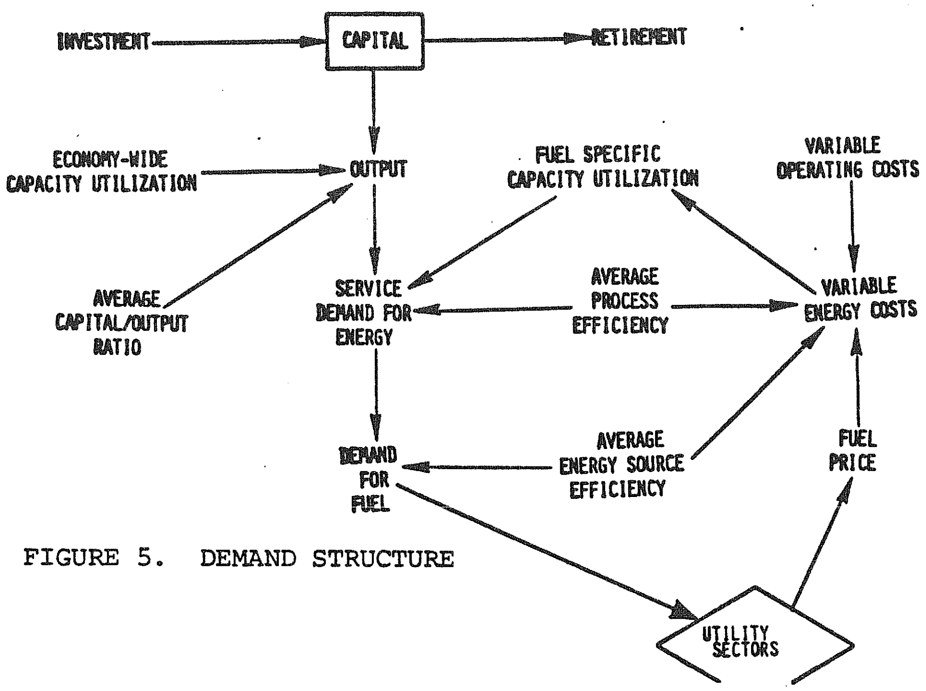

FIGURE 5. DEMAND STRUCTURE

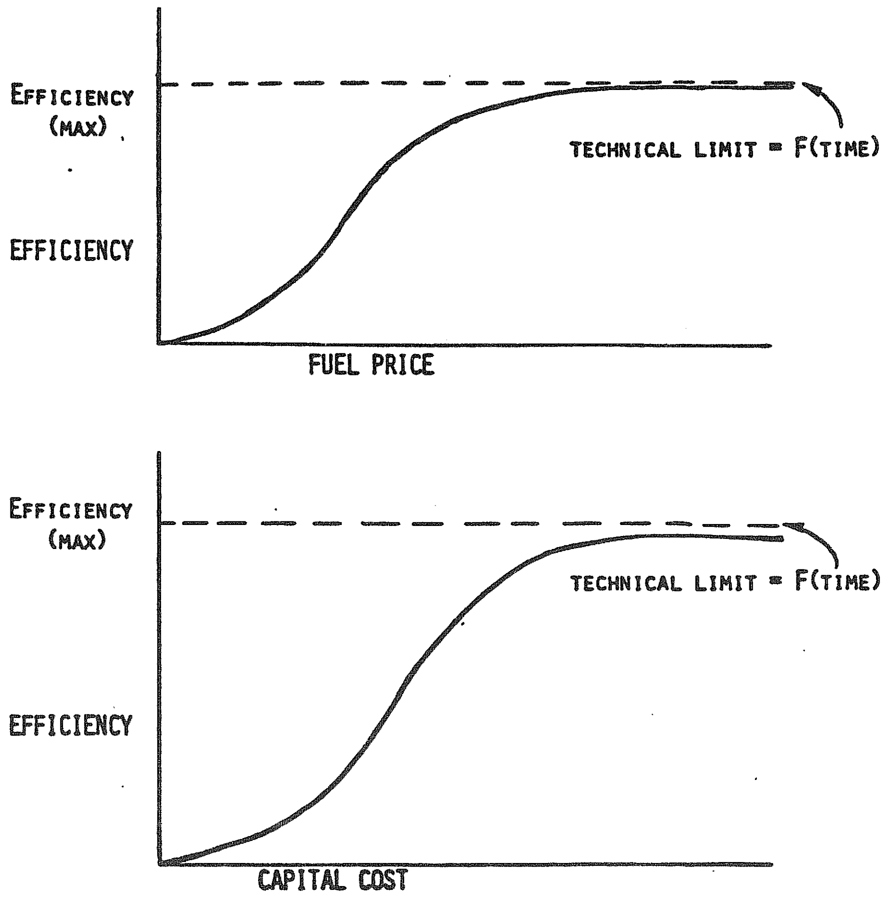

FIGURE 6. CAPITAL COST/EFFICIENCY CURVES

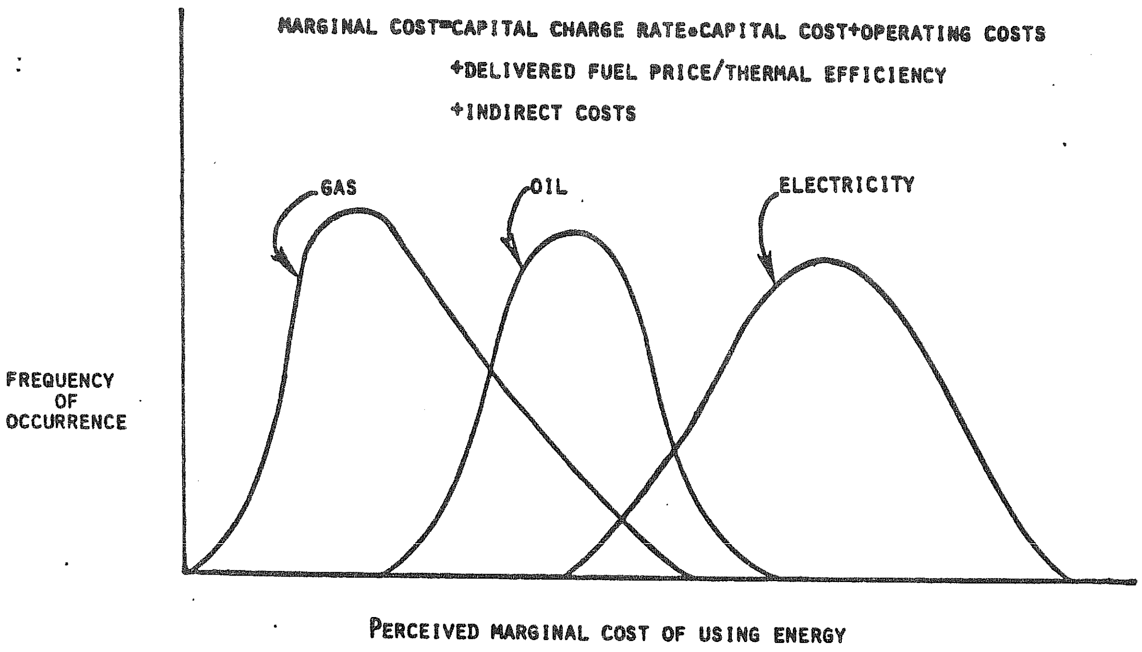

FIGURE 7. INVESTMENT MARKET SHARES (Fuel Specific)

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COMPOSITE LOAD FORECASTS: THE COMBINATION OF ALTERNATIVE MODELS

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1. Introduction.

One of the main obligations of a utility is to meet its customers' load demands. For electric utilities in particular, this obligation requires the development of rigorous procedures for forecasting future load growth. Historically, load forecasters have relied on two types of forecasting models. The first method is the traditional structural econometric model, and the second is the time-series model fitting approach. Each of these two methodologies has its own merits and drawbacks.

Through the structural econometric model, the analyst can directly employ the causal relationships suggested by economic demand theory. In other words, the load forecasting model is often stated as a derived demand model where economic and demographic variables are used to "explain" the customer's demand for electricity. For applied forecasting work, however, econometric models may not always be plausible due to the lack of data on certain explanatory (theoretically causal) variables or due to the difficulty of forecasting the explanatory variables.

Time-series models are essentially a sophisticated method of extrapolation, where loads are forecasted from current and past load levels. The problems associated with explanatory variables are thus avoided; however, no insights into causal relationships or elasticity effects are obtained. In addition, the time series approach is quite sensitive to shifts in demand, whereas (hopefully) the econometric model can account for such shifts via its causal variables.

Frequently analysts might prefer one type of model over the other due to the above reasons; however, a load forecaster may choose between an econometric model and a time-series model merely on the basis of forecasting accuracy. The usual practice is to determine which is the better or best forecast by means of some criterion such as mean square error. The selected model and its resulting forecasts are then used and the other model(s) and forecasts are discarded. By discarding what is considered to be the poorer forecast(s), however, some useful information is often lost. It is frequently the case that a composite (combined) forecast, i.e., some combination of the two or more independent load forecasts, proves to be superior to the "best" of the single forecasts.

This paper examines alternative procedures for obtaining linear composite load predictions from two independent load predictors or forecast series. Three formulations of composite predictions are considered: (i) a single fixed combination weight, w, where w is the weight attached to one of the independent forecasts, 1-w is the weight attached to the other, and w is assumed to be bounded by zero and one; (ii) two fixed weights, w_1 and w_2, which are not constrained in magnitude and are considered to be jointly optimal; and (iii) a single time varying weight, w_t, which allows for the relative efficiency of the two independent forecasts varying with time, t. Five alternative means of estimating these combination weights are explored in the paper. First a least squares estimator is specified for the simple fixed weight w, and then a minimum variance (in terms of the composite prediction error) estimator of w is presented. An estimator for the jointly optimal weights, w_1 and w_2, is developed using an Aitken two-state least squares procedure. Finally, two alternative methods for estimating the time varying weight are discussed. The first allows for a gradual adjustment in the weighting factor, w_t, and the second allows the forecaster to specify the importance of the most recent forecast errors (i.e., the forecaster may wish to assign less importance to the most recent errors which may be the result of an unusual or large disturbance). The composite load forecasting procedures are illustrated using hypothetical examples of an econometric load forecasting model and a Box-Jenkins (ARIMA) load forecasting model. Before addressing the composite load forecasting procedures, techniques for evaluating forecasts are discussed in the next section. The concluding section outlines possible problems with composite load forecasting procedures.

2. Evaluation of Forecasts.

The desirable properties of economic forecasts and evaluation procedures are covered in detail elsewhere (Granger and Newbold, 1973; Dhrymes et al., 1972; Theil, 1961 and 1966); therefore, only the basic features of selected means for evaluation will be discussed here. Before delving into evaluations, however, it seems fruitful to distinguish between the evaluation of a forecasting equation using sample period data and using post-sample period data.

Empirical models are often evaluated by estimating the values of the endogenous variables over the sample period employed to estimate the model. Let z_t, $t = 1, \ldots, n$, denote the observations on the endogenous variable, and let the observations of the h exogenous variables used for estimation be $x_{1t}, x_{2t}, \ldots, x_{ht}$, $t = 1, \ldots, n$. It is assumed that an empirical estimation procedure is used to obtain estimates $b_1, b_2, \ldots, b_h$ of the parameters $B_1, B_2, \ldots, B_h$ from the following relationship:

$$Z = XB + u, \tag{2.1}$$

where Z is a $nx1$ vector of observations on the endogenous variable, X is a nxh matrix of observations on the exogenous variables, B is a $hx1$

vector of unknown parameters, and u is a $nx1$ vector of unobserved disturbance terms. Given the vector of parameter estimates, b, sample period explanations of the endogenous variables can be obtained, i.e.,

$$\hat{Z} = Xb \quad , \tag{2.2}$$

where $\hat{Z}$ is a $nx1$ vector of sample period explanations, $\hat{z}_t$, $t = 1, \ldots, n$. Since the sample series, z_t, $t = 1, \ldots, n$, was used to estimate the model, the values z_t are not forecasts and shall be referred to as sample period estimations or explanations. It follows that the error vector for the sample period is obtained from

$$e = Z - \hat{Z} \quad , \tag{2.3}$$

where e is a $nx1$ vector of error terms $e_1, e_2, \ldots, e_n$.

When convenient some sample period data, endogenous and exogenous variables, should be "saved" or omitted from estimation. These saved observations can then be used to test the forecasting performance of the estimated model. Furthermore, since the saved observations on the endogenous variables were not used in estimating the parameters of the model, their estimated values will be forecasts. Let us assume that there is a post-construction sample (Dhrymes, et al., 1972, p. 306) of m observations, i.e., $z_{n+1}, z_{n+2}, \ldots, z_N$, where $N = n + m$. These extra observations may be the m time series points following, say, day n, or they may be m additional cross-section observations at the same point in time. Using the parameters obtained from the sample period data, the post-construction sample forecasts are

$$\hat{Z}_p = X_p b \quad , \tag{2.4}$$

where $\hat{Z}_p$ is a $mx1$ vector of forecasts, X_p is a mxh matrix of post-construction observations on the exogenous variables, and b is as defined before. It follows that the post-construction forecast errors are

$$e_p = Z_p - \hat{Z}_p \quad , \tag{2.5}$$

where e_p is a $mx1$ vector of forecast errors and Z_p is a $mx1$ vector of actual values of the endogenous variables for the post-construction sample.

Five general types of criteria or measures for evaluating econometric models, and more specifically forecasting models, have been outlined by Dhrymes et al. (1972): (1) Single-variable measures or point criteria, (2) tracking measures, (3) error decompositions, (4) comparative errors, and (5) cyclical and dynamic properties. Since these criteria have been extensively discussed in the references cited above, they will only be briefly outlined here.

Single-variable measures include, among others, the mean forecast error, the mean absolute forecast error, and the mean squared error of the forecasts (the average of the forecasting errors). Each of these measures collapses the series of forecast errors into a scalar measure. Undoubtedly the most popular is the mean squared error (MSE) or the root mean squared error (RMSE), (Granger and Newbold, 1973, p. 39; Dhrymes et al., 1972, p. 306), which may be written as

$$\text{RMSE} = (\text{MSE})^{1/2} = \left(\frac{1}{m} \sum_{t=1}^{m} e_t^2 \right)^{1/2} . \tag{2.6}$$

The use of the RMSE as a measure of forecast quality arises from the general specification of a least-squares criterion. More specifically, a forecaster may be pictured as desiring to minimize the loss function

$$L(B, b) = E\,[\hat{Z} - E(Z)]'C\,[\hat{Z} - E(Z)] \quad , \tag{2.7}$$

where C is a symmetric positive definite matrix which allows for the possibility of giving different weights to errors at different observation points. In general C is not known and is substituted with an identity matrix.1/

In contrast to measures like the RMSE, tracking measures examine different segments of the forecast series. For instance, the ability of a model to forecast turning points is often listed as a desirable criterion. Nelson (1972) argues, however, that "turning point errors are of no special interest in and of themselves" in that they are only associated with large disturbances in the predicted series. In other words, success in anticipating turning points can be attributed to success in accuracy. Thus, Nelson feels we should not restrict our attention to turning points but rather to accurate prediction of large disturbances and, therefore, should concern ourselves with minimization of MSE. Tracking criteria, nevertheless, offer an interesting evaluation of forecasting errors and should not be entirely ignored.

The third category of evaluation measures, i.e., error decompositions, consists of estimates of the bias and variance of forecast errors, errors in start-up position versus errors in the predicted changes, and identification of model subsectors transmitting errors to other sectors. An extensive discussion of decomposing the average squared error or MSE into various measures is given by Theil (1961). Granger and Newbold (1973) present a critical discussion on the usefulness of Theil's measures.

Comparative errors measurements include the comparison of the forecasting errors of one's model with the errors of various "naive" forecasts, such as, a simple linear trend or using last period's observation to predict next period's, etc. Dhrymes et al., (1972) suggest using Box-Jenkins or ARMA models as a more rigorous alternative to naive models. It can be demonstrated, however, that the ARMA model can be derived from the structural

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1/ This substitution is justifiable as long as control variables are not involved and the model is not used directly for decision-making purposes. In a practical application, however, any notions of loss should be incorporated in C.

form and is, thus, not such a naive process. Comparisons may also be made with judgmental, consensus, or other non-economic forecasts or with other econometric forecasts.

The cyclical and dynamic properties of forecasting errors are the last type of evaluation measurements mentioned above. For a dynamic model to be stable the covariance matrix of the forecast errors must be composed of finite elements. Box and Jenkins (1976) have suggested using spectral techniques to test the estimated residual error series for serial correlation and to see if it significantly differs from a white noise. The relationship between the forecasts and the original series may also be examined using cross-spectral analysis techniques.

As can be seen from the above brief outline, various measurements are available for evaluating forecasts. For the purposes of this expository paper it was felt that it would be sufficient to use a single-variable measure; i.e., the RMSE.

3. The Combination of Forecasts.

Given a situation in which there are two (or more) forecasts for the same event, the frequent practice is to determine which is the better (or best) forecast by means of some criterion such as RMSE. The better forecast is then used, and the other is discarded. By discarding the poorer forecast, however, some useful information is often lost. It is often the case that a combined forecast, i.e., some combination of the two independent forecasts, proves to be superior to the "best" of the two single ones, (Bates and Granger, 1969).

> In short, relative accuracy is not an appropriate basis for choosing one prediction to the exclusion of the other; rather, even a very inaccurate prediction would generally be included in a minimum variance composite. (Nelson, 1972, p. 911).

Let us assume there are two predictors or forecast series, P_{1t} and P_{2t}, $t = 1, 2, \ldots, T$, which produce forecast errors e_{1t} and e_{2t}, $t = 1, 2, \ldots, T$. A linear composite prediction using these two predictors may be written as

$$Z_t = w_1 P_{1t} + w_2 P_{2t} + u_t \,, \tag{3.1}$$

where Z_t is the actual value for period t, w_1 and w_2 are fixed coefficients, and u_t is the composite prediction error. In the case that both P_{1t} and P_{2t} are conditionally unbiased and the forecast errors are bivariate stationary (Nelson, 1972, p. 910; Granger and Newbold, 1973, p. 41), then (3.1) may be rewritten as

$$Z_t = wP_{1t} + (1 - w)P_{2t} + u_t \,, \tag{3.2}$$

where w is a single fixed combination weight. If $0 \leq w \leq 1$, then w would provide a useful measure of the relative efficiency of the two independent forecasts, P_{1t} and P_{2t}. Granger and Newbold (1973, p. 42) have pointed out, however, that unfortunately this restriction on w need not hold either in the sample or the population case. Earlier empirical applications by the senior author of this paper have lent support to this conclusion.

The coefficient w in (3.2) is assumed to be fixed for different values of t. Given that the relative efficiency of the two independent forecasts, i.e., P_{1t} and P_{2t}, may vary with t, it may be desirable to re-state (3.2) with a combination weight that changes with t, i.e.,

$$Z_t = w_t P_{1t} + (1 - w_t) P_{2t} + u_t . \tag{3.3}$$

In this situation, the value of the combination weight is allowed to change as evidence is accumulated about the relative performance of the two independent forecasts, (Bates and Granger, 1969, p. 453).

Five alternative means of estimating the combination weights discussed above will be explored in this paper. First, the simple fixed weight in (3.2) will be estimated using a least squares criterion and then using a minimum variance criterion. The jointly optimal weights in (3.1), i.e., w_1 and w_2, will then be estimated employing a two-stage least squares procedure. Finally, the time varying weight w_t will be estimated by two alternative methods. Given this brief discussion of composite forecasts, the estimation procedures to be used are individually discussed below.

4. Linear Composite Prediction with Single Weight

The least squares estimate of w in (3.2), i.e., that estimate which minimizes the sum of squared composite errors or

$$\sum_{t=1}^{T} e_{ct}^2 ,$$

where $e_{ct} = Z_t - P_{ct}$ and P_{ct} is the composite forecast estimate of Z_t, is given by

$$\hat{w} = \frac{\Sigma (P_{1t} - P_{2t})(Z_t - P_{2t})}{\Sigma (P_{1t} - P_{2t})^2} . \tag{4.1}$$

It is easily seen that $\hat{w}$ is no more than the coefficient of the regression of P_{2t} prediction errors on the difference between the two predictions, i.e., $P_{1t} - P_{2t}$. Obviously, the greater the ability of the difference between the two independent predictions to account for the prediction errors of P_{2t}, the larger will be the weight given to P_{1t}, i.e., the closer $\hat{w}$ will be to one. Moreover, if all of the information provided by P_{2t} is already incorporated in P_{1t}, then $\hat{w}$ should be approximately equal to one.

An alternative to the minimization of the sum of errors squared is the minimization of the variance of the combined forecast errors, v_c^2, which can be written as

$$v_c^2 = w^2 v_1^2 + (1 - w)^2 v_2^2 + 2rwv_1 (1 - w)v_2 , \quad (4.2)$$

where v_1^2 and v_2^2 are the variances of the two individual forecast errors and r is the correlation coefficient between the errors in the first set of forecasts and those in the second set, (Bates and Granger, 1969, p. 453). It can easily be shown that the minimum variance estimate for w is given by

$$\tilde{w} = \frac{S_2^2 - \hat{r} S_1 S_2}{S_1^2 + S_2^2 - 2\hat{r} S_1 S_2} . \quad (4.1)$$

where S_1^2 and S_2^2 are the sample variance of e_{1t} and e_{2t} respectively and $\hat{r}$ is the sample correlation between e_{1t} and e_{2t}, (Granger and Newbold, 1973, p. 41; Nelson, 1972, p. 911).

5. Linear Composite Prediction with Jointly Optimal Weights

The composite forecast given by the above combination weight estimates may not be optimal for a decision maker whose objective is to select weights which minimize expected loss, (Nelson, 1972, p. 912). Since in general the particular loss function will be unknown, Nelson has suggested incorporating the covariance matrix of composite errors in the loss function, i.e.,

$$L = \underline{u}' Q^{-1} \underline{u} , \quad (5.1)$$

where $\underline{u}$ is the vector of errors across variables and Q is the covariance matrix of the composite error terms in (3.1). In order to minimize the average loss given by function (5.1), separate parameters for P_{1t} and P_{2t}, i.e., w_1 and w_2 as in (3.1), can be estimated by Aitken's generalized least squares. Obviously, Q is unknown, therefore, the error estimates obtained from applying OLS to (3.1) can be used to estimate Q along the lines of Zellner's (1962) method for seemingly unrelated regressions. It follows that the estimates for w_1 and w_2 may be expressed as

$$\begin{bmatrix} \hat{w}_1 \\ \hat{w}_2 \end{bmatrix} = (P'\hat{Q}^{-1}P)^{-1} P' \hat{Q}^{-1} Z , \quad (5.2)$$

where P is a $Tx2$ matrix of the independent forecasts P_{1t} and P_{2t}, $\hat{Q}$ is the estimate for Q, and Z is the $Tx1$ vector of the actual values Z_t.

6. Linear Composite Prediction with Time Varying Weight

The previous methods for obtaining composite forecasts have not allowed the weighting parameters to vary with time. As discussed earlier it seems reasonable to expect that the optimal value of the estimate for w would change as evidence was accumulated about the relative performance of the two original forecasts, (Bates and Granger, 1969). Moreover, the relative efficiency of the two forecasts may be reversed during different times of the year, i.e., P_{1t} may give more accurate forecasts early in the season and P_{2t} may be relatively superior later in the season. In such cases, the linear composite prediction may be viewed as given in (3.3). Two methods for estimating the changing weight w_t will be explored in this paper. It is assumed that prior to employing these methods that an estimate of the constant weight parameter, say, w^*, has been previously obtained using either (4.1) or (4.3). This estimate will serve as the estimate for w_t at $t = 1$. Given this initial estimate, $w_1 = w^*$, two alternative methods are:

(a) $$\hat{w}_{at} = \frac{E_{2t}}{E_{1t} + E_{2t}} \quad , \quad t = 2, 3, \ldots, T \tag{6.1}$$

where

$$E_{2h} = \sum_{t=1}^{h-1} (e_{2t})^2$$

and

$$E_{1h} = \sum_{t=1}^{h-1} (e_{1t})^2 \quad ;$$

(b) $$\hat{w}_{bt} = x\hat{w}_{bt-1} + (1 - x) \frac{E_{2t}}{E_{1t} + E_{2t}} \quad , \quad t = 2, 3, \ldots, T, \tag{6.2}$$

where x is a constant of value between zero and one, (Bates and Granger, 1969, p. 454). Method (a) allows for a gradual adjustment in the weighting factor. The value of the constant factor x will depend upon the importance the forecaster attaches to the most recent forecast error. Bates and Granger (1969) indicated that in some instances, they found a negative value of x to give the best results - obviously, the choice of a value for x is not straightforward. In a forecasting situation, one may not have the opportunity to experiment with different values, i.e., time may not permit such experimentation. Moreover, the forecaster's, or more importantly the decision-maker's, (if the forecasts are to be used for decision-making) preferences may dictate the value or range of values for x. If the constant factor x is assigned a relatively large value, say, .70, then this it may be interpreted as a preference for assigning less weight to the most recent errors which may be the result of an unusual or large disturbance. In other words, a sudden decrease or increase in the individual forecast errors will not have a large influence on the estimated value for w_{bt}.

7. Combining Econometric and ARIMA Forecasts.

The introductory section contained a brief comparison of traditional econometric and time-series or ARIMA forecasting models. Given that each technique has advantages and disadvantages, a load forecaster may wish to combine econometric and ARIMA forecasts using one or more of the procedures discussed above. Frequently ARIMA forecasts are relatively more accurate in the short-term. In contrast, econometric models are often able to better predict more long-term economic shifts due to the "built-in" causality in their structure. Thus, a composite model like (3.3) may be preferable in this case in order to allow the "importance" of each model to change over time.

8. Conclusion.

The concept of combining forecasts is certainly not new to the general theoretical forecasting literature; various applications have also been reported. To the authors' knowledge, however, composite forecasts have not been employed in load forecasting. The application of the procedures discussed in this paper to load forecasting is certainly worth pursuing.

Nevertheless, the load forecaster is given a word of caution. As noted in Oliveira (1978), composite forecasts will not always be more accurate than individual forecasts. The properties discussed in this paper are theoretical statistical propeties; thus, there will be random deviations from the general tendencies. In other words, for some time periods or observations one might be more accurate by using an individual forecast. The load forecaster is encouraged to combine the composite forecasting procedures outlined in this paper with "professional judgment," as one should do with any statistical model.

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A PRACTICAL APPROACH TO SENSITIVITY ANALYSIS

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I. Introduction

The electric load forecast is the primary input to the generating capacity planning process. But without knowing the uncertainty surrounding forecasted demand, the capacity planning model cannot incorporate the optimal amount of flexibility into its capacity plan. Sensitivity analysis enables the model user to quantify the uncertainty of the model's outputs.

Sensitivity testing is defined by a Congressional manual on simulation modeling as the "running of a simulation model by successively changing the status of the system...and comparing the model outputs to determine the effects of these changes" (Congress 1975, p. 129). Such testing provides the model user with five capabilities:

1. To quantify the uncertainty of the model's output;

2. To identify the sources of uncertainty and thus help to focus data gathering and model development efforts;

3. To debug the model by exposing errors in the coding and logic;

4. To search the model for new behavior modes;

5. To search for a set of parameter assumptions which will generate preselected results.

Sensitivity analysis is often considered to be an important step in the construction of a computer model. However, the following attributes of energy forecasting and electric utililty planning models make sensitivity analysis difficult:

1. There are a large number of model parameters;

2. The output generated may consist of patterns which vary with time;

3. The cost of running the model a large number of times is high.

A methodology for structuring and facilitating sensitivity analysis was developed at the Los Alamos National Laboratory and verified by Control Data Corporation. The methodology and the software implentation are referred to as the "HYPERSENS" system, because of the use of the Latin hypercube sampling procedure. The HYPERSENS system can be applied to any computer code or simulation model; however the current implementation is for simulation models written in the DYNAMO language.

II. Tolerance Intervals on U.S. Oil and Gas Consumption by Electric Utilities

A. HYPERSENS Procedure

In a typical application of the HYPERSENS system, the analysis begins with the selection of the model parameters to be examined. Each input parameter must be described by its probability distribution and range of plausible values. The analyst selects the desired sample size for the experiment, which will equal the number of model runs. To determine the parameter values to be used in each computer experiment, the range of each input variable is divided into N equal intervals. Then, a value is selected from each interval according to its conditional distribution, and values are assigned at random to the N model runs.

The computer experiments are run using the assigned parameter values, and the results are stored along with the information on the input values and in each calculation. HYPERSENS uses this information to identify influential input parameters. Indications of the relative importance of different inputs are found using the partial rank correlation coefficient (PRCC) with critical values from the normal correlation coefficient. Time plots of the PRCC's allow the analyst to select the most influential inputs during different parts of a simulation.

The analyst determines whether the most important parameters are independent. If those parameters are independent, then the confidence bounds of the model's outputs may be interpreted in probabilistic terms. Otherwise the model must be altered to remove the correlation among the most important input parameters. With the new model and new parameters, sensitivity testing starts again. The iterative process of the HYPERSENS system is illustrated in Figure 1.

B. The Illustrative Example

A system dynamics model designed to simulate the operations of a hypothetical investor-owned utility company subject to rate-of-return regulation by state public service commissions will be used to demonstrate the HYPERSENS procedure. The model contains 45 parameters of interest with some unknown degree of influence and uncertainty.

With the parameter ranges as a starting point, a set of twenty simulation experiments were designed using the Latin hypercube sample rules to ensure full coverage of the 45-dimensional input space. The final result of the sampling analysis is a set of instructions for twenty computer simulations with different parameter values for each of the 45 parameters.

The information obtained from the twenty simulations is summarized in Figure 2A, which shows the statistics for the first iteration analysis of the Oil and Gas Used in Electricity Generation (OUEG). Figure 2A shows the mean, maximum, and minimum results from the twenty experiments. The variability among the different simulations is apparent from comparing the minimum and maximum values, and also from the behavior of the standard deviation over time. The statistics show that the nominal and mean results are quite close, and that the maximum value is almost twice as large as the mean in the year 1990. Notice that the Figure 2A information begins in the year 1980--the first year of the model projections into the future. Thus, the ranges of plausibility on input parameters must be

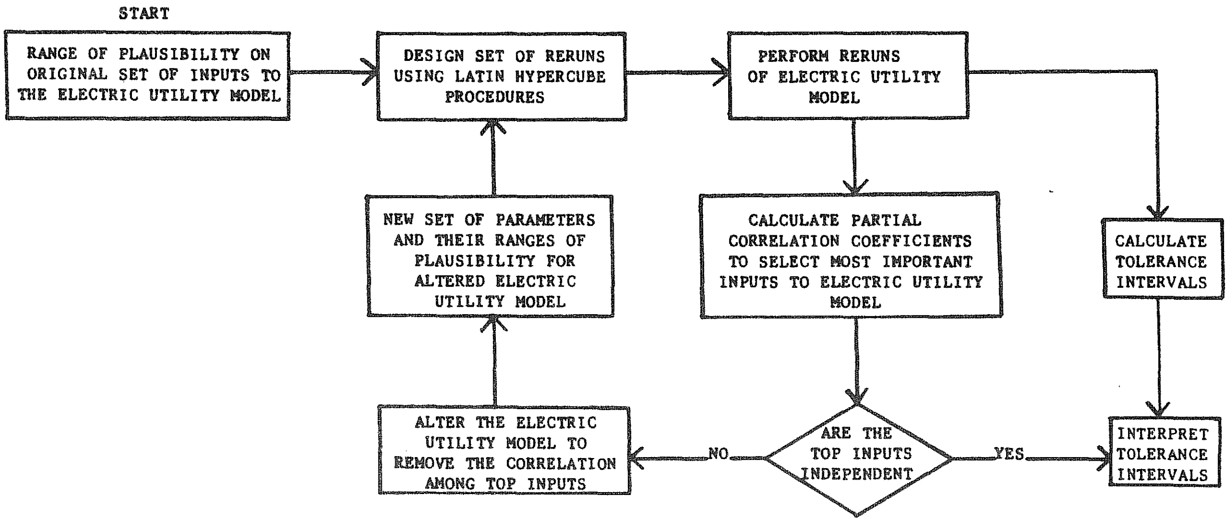


Fig. 1 Overview of the iterative application of Latin Hypercube Sampling to obtain interpretable tolerance intervals on model output.

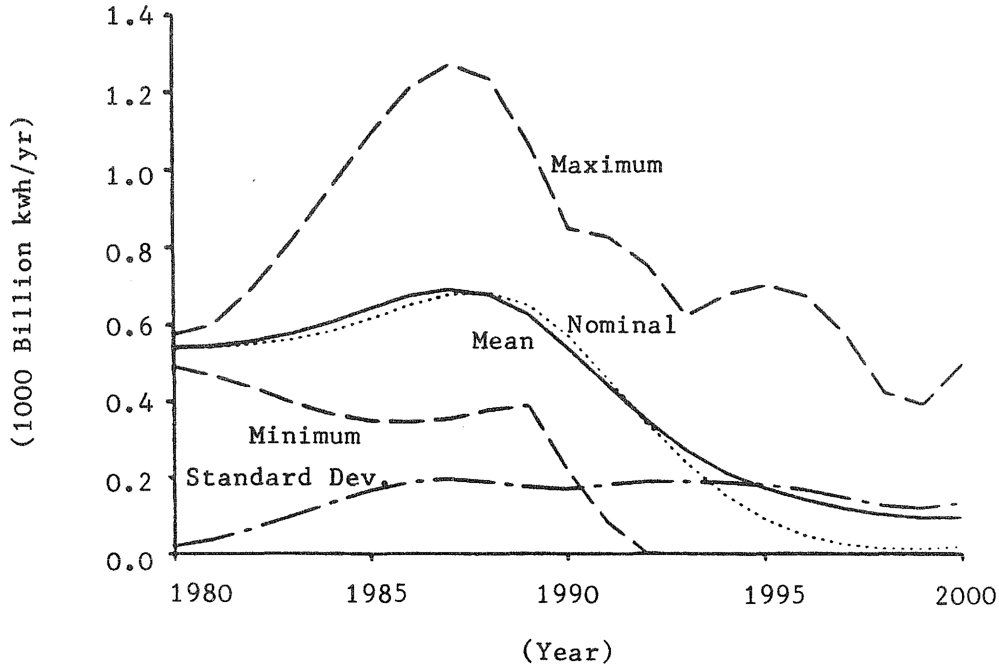


Fig. 2A Summary statistics from the first iteration analysis.

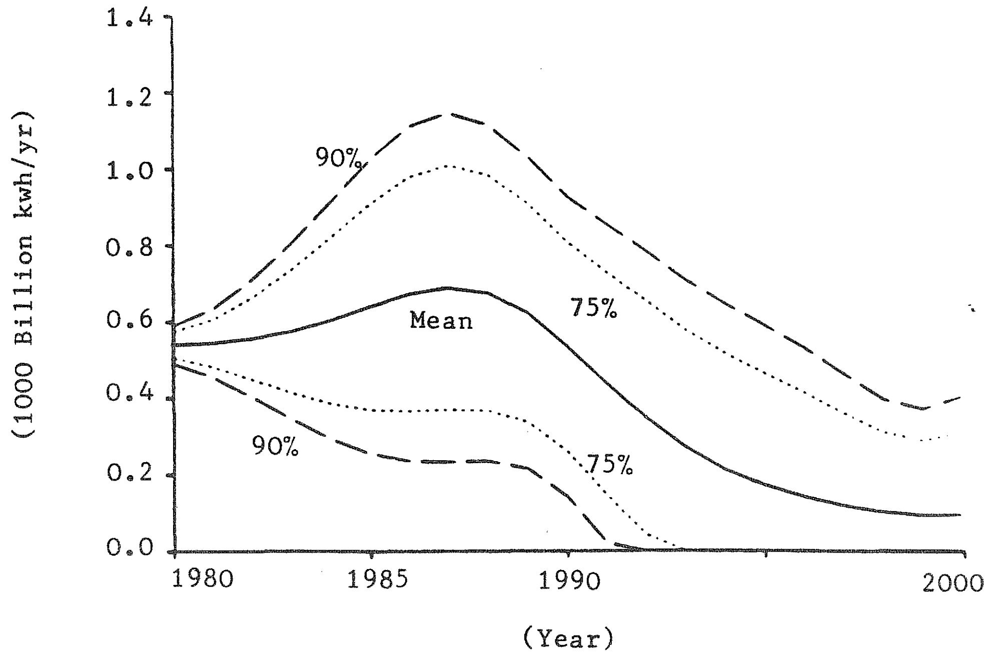


Fig. 2B Tolerance intervals from the first iteration analysis.

expressed in terms of an uncertain estimate of parameters in future years.

Figure 2B shows the tolerance intervals obtained from the first iteration analysis of OUEG. These limits encompass the range of values that could be expected in either 75% or 90% of the simulation runs of the model.

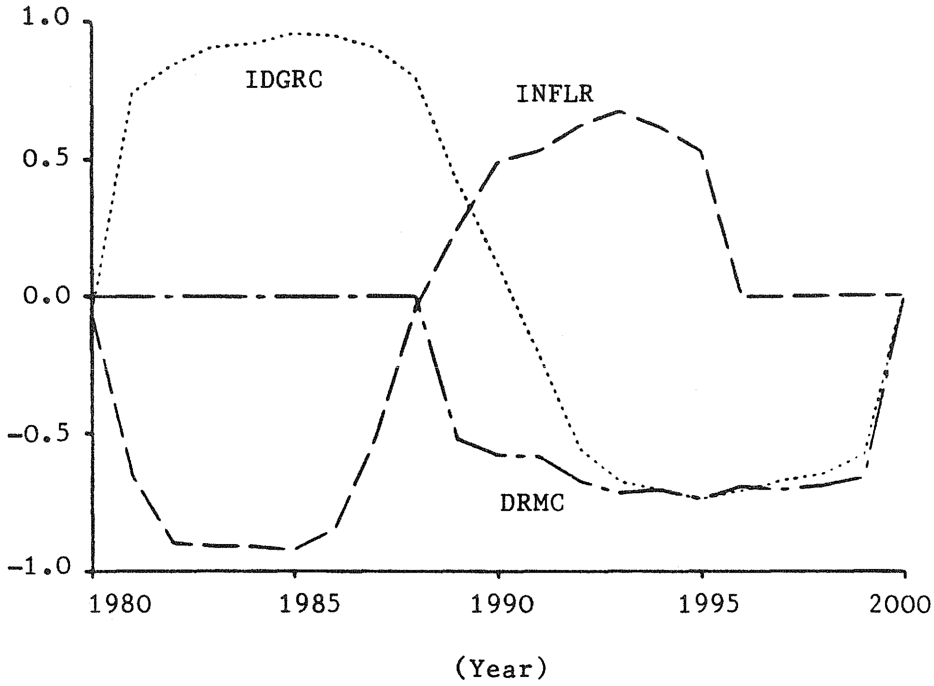
Figure 2C gives the partial correlation coefficients between the value of OUEG in a given year and the values of the important input parameters. Strong positive or negative correlation indicates that the particular input parameter is especially influential during that time period. Figure 2C shows that the Indicated Demand Growth Rate Constant (IDGRC) is positively correlated with OUEG in the 1980's.

The inflation rate (INFLR) is also highly correlated with OUEG, but in a pattern the opposite of IDGRC. A third input which exhibits strong influence on OUEG is the Desired Reserve Margin Contant (DRMC).

Three additional inputs are found to have a strong influence on OUEG during the 1980's: the availability factor for coal plants (NCAFC), for nuclear plants (LWAFC), and coal plant operating lifetime (NCCL).

The Figure 2 results do not reveal any spurious tendencies, or illogical results. One can only interpret the tolerance intervals in Figure 2B in probabilistic terms, however, if the most important inputs to the model are uncorrelated. This is not the case. Two collinearities exist between the top six inputs identified in Figure 2C. First, DRMC cannot be specified independently from the availability factors for the nuclear and coal power plants. The second colinearity involves the availability factors for the coal and nuclear power plants which should be positively correlated, as both plant types have certain components in common. Following the approach diagrammed in Figure 1, the next step is to remove these correlations through alterations in the electric utility simulation model.

To remove the collinearity betwen DRMC and the two availability factors, the desired reserve margin is calculated as the sum of a Minimum Reserve Margin from Availability Factor (MRMAF) and a Reserve Margin Over Building Increment (RMOBI). The portion of the desired reserve margin which is dependent on the availability factors of the new coal and nuclear plants is calculated internally. The overbuilding increment is a new parameter which is varied to reflect the inclination of utility companies to overbuild to displace oil and gas. This new parameter, RMOBI, is not correlated with the availability factor for the new coal and nuclear plants. To remove the collinearity between the two availability factors, three new parameters have been added to the model: a steam power plant availability factor (STAFC), an incremental difference between coal and nuclear plant



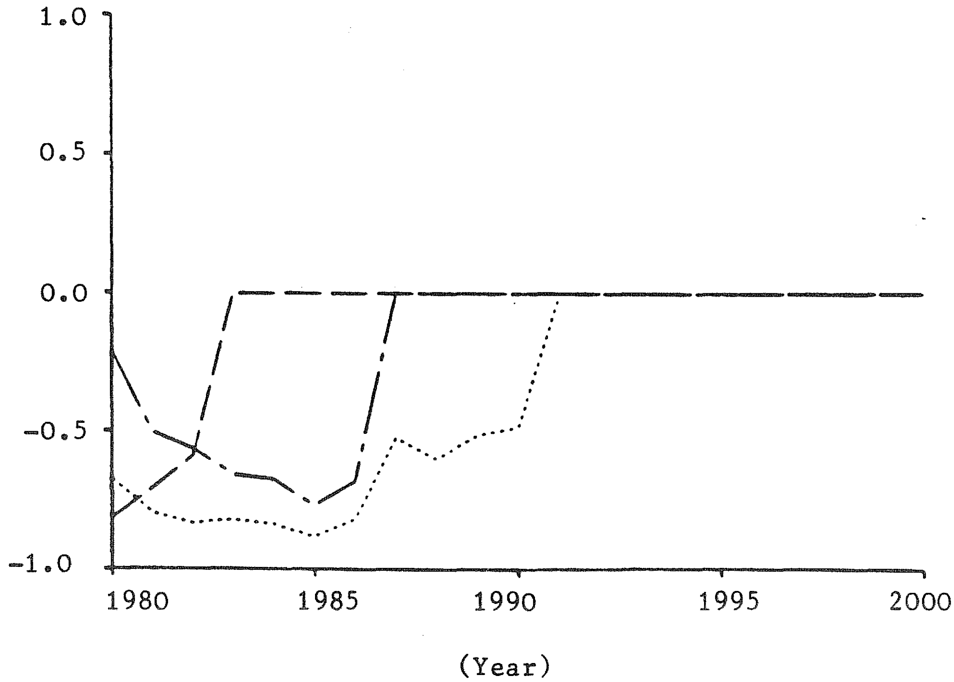


Fig. 2C Partial correlation coefficients from the first iteration analysis.

availability (NCAFD), and an incremental difference between nuclear plant availability and steam plant availability (LWAFD).

C. Results from the Second Iteration

The list of input parameters is slightly modified for the second iteration. DRMC is replaced by the new variable, RMOBI; and LWAFC and NCAFC are replaced by the three parameters described above. HYPERSENS is used to design a set of twenty simulation experiments with the model's 46 input parameters. The results from the new set of twenty simulations are shown in Figure 3.

Figure 3A reports the summary statistics for the second iteration analysis of OUEG. A comparison of 2A and 3A shows that the maximum value of OUEG around 1987 is lower in the second iteration. Thus, one would expect the tolerance intervals to be somewhat narrower in the second iteration analysis. Figure 3B shows that the tolerance intervals do become narrower with the altered model. The 90% coverage in 1987, for example, runs from around 300 to 950 billion kwh/yr in the second iteration, versus 250 to 1150 billion kwh/yr in the first iteration. The reduction in the size of the tolerance interval from one iteration to the next may be attributed to the removal of the collinearities between the most important inputs in the model.

Based on the partial correlation coefficients the most important input parameters are: IDGRC, INFL, and NCCL from the first iteration and the new parameters RMOBI, NCAFD, and LWAFD. An important result is that the six variables selected as having the most influence on OUEG are not correlated with one another in an important manner. Thus, the tolerance intervals in Figure 3B can be interpreted in probabilistic terms.

D. A Measure of Parameter Uncertainty

The range of variation in the model projections of OUEG is represented by the tolerance intervals in Figure 3B. The mean value of the forecasts is bordered by two sets of curves representing 75% and 90% coverages. Thus one can readily see the uncertainty in OUEG forecasts due to parameter uncertainty. An examination of the graphs in the year 1990, for example, shows the mean value to be about 480 billion kwh/yr. We expect 75% of the OUEG forecasts to lie between 240 and 690 billion kwh/yr and 90% of the forecasts to lie between 150 and 780 billion kwh/yr. These intervals are calculated at the 95% confidence level.

These tolerance intervals represent only the parameter uncertainty in the model forecast. That is, they represent the uncertainty in OUEG forecasts given that one accepts the structure of the electric utility model as an accurate representation of the nation's electric utility industry.

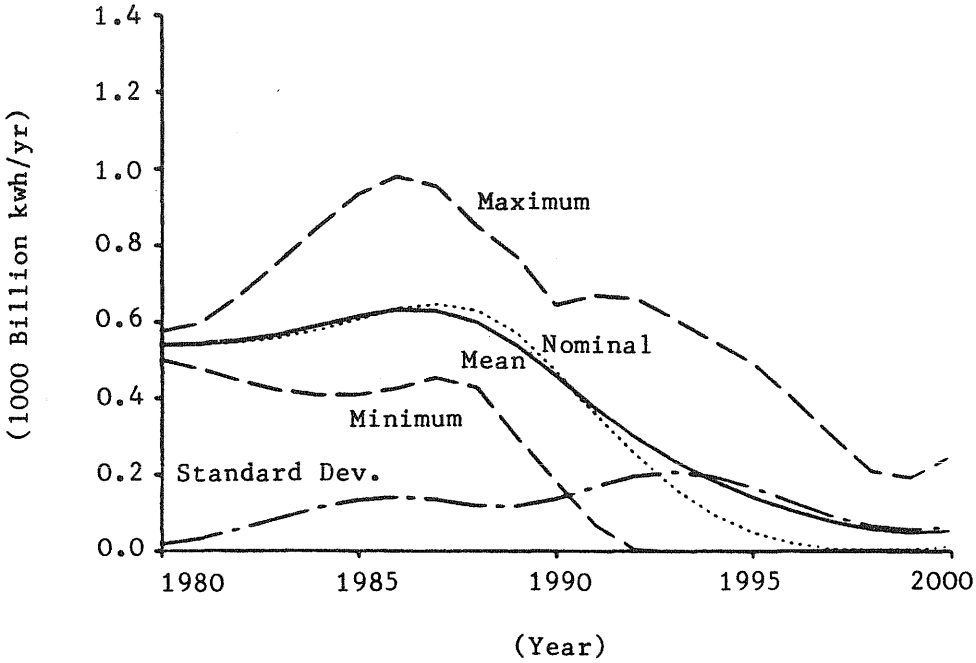


Fig. 3A Summary statistics from the second iteration analysis.

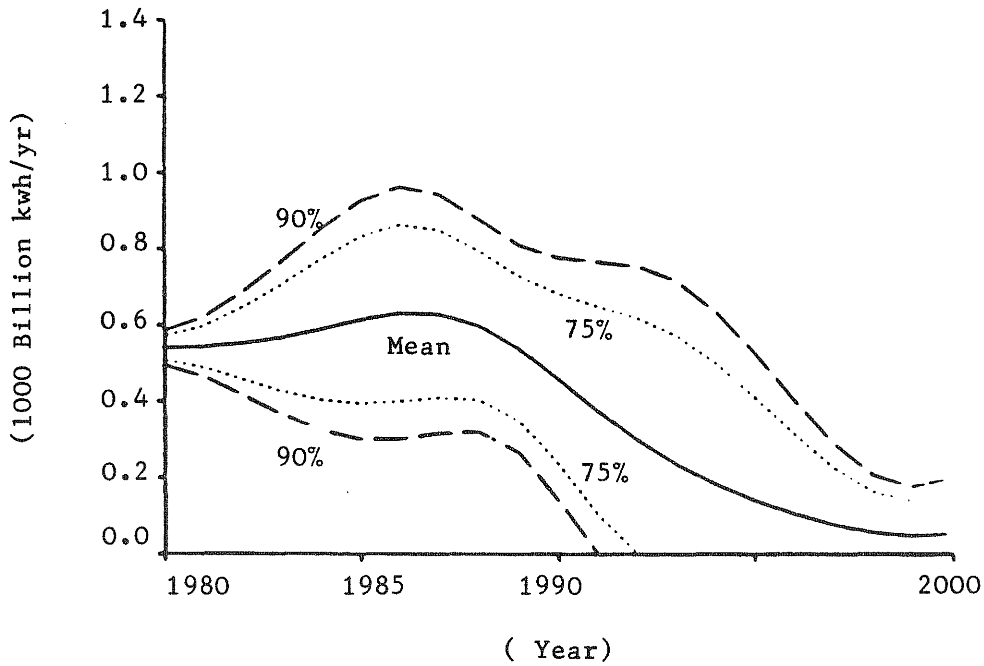


Fig. 3B Tolerance intervals from the second iteration analysis.

III. Suggestions for Practical Application

The combined research efforts of the Los Alamos National Laboratory and Control Data Corporation have led to a practical approach to sensitivity testing that all electric utility industry analysts would successfully apply to their major modeling projects. To gain the advantage of detailed sensitivity testing, note these suggestions for practical application:

1. Input Ranges: Expect that the task of specifying the ranges of plausility on model inputs will be a difficult initial obstacle, especially for large models that may have outgrown their oroginal documentation.

2. Model Shakedown: Be prepared to observe spurious behavior when the model is run many times with the HYPERSENS system. Accept the needed changes in the model as a problem with the model structure and not a problem with the sensitivy testing procedures.

3. Sensitivity of the Sensitivity Testing Results: Be prepared to test the results of the sensitivity analysis to changes in the starting assumptions. For example, you may be unsure of whether a uniform or normal distribution best describes a given input. One can simply repeat the sensitivity analysis to see if the tolerance intervals or PRCC'S are affected with a change in the probability distribution.

Investigators willing to follow these practical suggestions should be able to perform the type of analysis shown here without incurring significant computer costs. For example, the computer related costs of the Figure 2 calculations with 20 runs of the electric utility model cost about $50.

The HYPERSENS system described here is particularly valuable for electric utility industry models. Load forecasting models typically vary with time, require a large number of variables, and their results are important inputs to the generating capacity planning process. The procedures described here facilitate the quantification of uncertainty in load forecasts, and therefore provide important information to utility industry planners.

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AN ECONOMETRIC LOAD FORECASTING MODEL FOR IOWA UTILITIES: AN EMPIRICAL ASSESSMENT[1]

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Introduction

Econometric forecasting models of electric load demand have received mixed reviews over the last decade. Principally, the performance of these models in accurately forecasting peak loads for extended time periods has not been adequate. This lack of precision has enabled the utility industry to revert back to the traditional models that are as inaccurate if not more inaccurate in forecasting load demand, thereby continuing the problem.

The benefits versus the costs of econometric load forecasting models have been addressed in many previous forums. Our principal task in this paper is to present an overview of a mathematical model (derived and used by the Rates Research and Policy Division of the Iowa State Commerce Commission) that has accurately forecasted load demand on a company by company basis. We shall present the model, the data necessary to drive the model, the assumptions made about the rates of growth of the economic variables and the weather variables that obviously influence peak electric demand. The explicit recognition that the demand for energy is also dependent on other factors, such as income, weather and the economy leads to model those relationships as a basis for demand forecasting. Clearly, just knowing how much electricity consumers had consumed in the past does not offer a guide to know what they will consume in the near as well as distant future under continuously changing economic conditions, prices and availability of energy resources. In addition, a great deal of global, as well as local, socio-political environments influence the energy demand for the future.

A distinction between long-run and short-run demand functions is useful for policy analyses. Short-run demand refers to an existing demand function with its immediate reaction to price changes, income fluctuation, etc. Whereas, long-run demand is that function which will presumably exist as a result of changes in prices, income, promotion or product improvement, technological change and changes in tastes, after enough time is allowed to let the market adjust itself to the new situation. The direct and indirect impacts of the change in the conservation efforts on the part of both the consumers and

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[1]Two people have had significant influence in the formulation and development of this study, principally, Dr. Robert J. Latham and Mr. Richard H. Schaeffer. However, the interpretation, conclusion and any errors are the sole responsibility of the authors.

producers of electric appliances and changes in general economic conditions have long lasting influence on the consumption of electric energy and its supply behavior.

Demand analysis for electricity assumes that the individual's energy use reflects not only one's personal needs, but also one's income, the level of energy prices and the prices of other goods. Throughout the analysis, individual's needs are considered to be given while income and prices are allowed to vary. Electricity is not an end use good, but is consumed only in conjunction with the durable goods, such as refrigerators, air conditioners, heaters, and other appliances and machines. Therefore, consumers' full response to a change in demand component or a demand determining factor of electricity depends on the quality, efficiency and durability of the electric appliances. In other words, the demand for electricity is a derived demand that is based on the demand for and the intensity of use of such appliances.

Methodology and Data Base

Electricity is a single homogenous nonstorable commodity. The great variety of the consumers of electricity and its end uses, from running a home TV set to melting scrap steel in an industrial arc furnace, creates a myriad of dissimlar demands. In the rapidly changing environment of the utility industry, the so-called physically based engineering approach of end use forecasting, focusing only on physical factors (e.g., technological efficiency of appliances), can easily miss the emergence of new end uses and ignore some other very important effects, such as the impact of rising energy prices as a stimulus to conservation, as well as other changes in consumers' preferences. Consequently, a major trend in energy demand forecasting is the effort to integrate both the physical factors and the behavioral factors into a single model. The approach allows a more comprehensive examination of the many diverse influences that shape the demand for energy. This modeling effort that includes all factors, economic and non-economic, as characteristics of energy forecasting is known as the econometric approach.

The relationship of hourly per capita kilowatt demand as a function of prices, income, wealth, and weather is tested using a mathematical specification. Estimates of the parameters of this model are obtained via the ordinary least squares method. These parameter estimates, derived from a pooled time series-cross section data base consisting of 14 years of observations, are not only the hourly elasticities of demand with respect to prices, income, wealth and weather, but are also the principal components that forecast loads on an hourly basis for the desired future year.

The data that drive this particular model are unique to Iowa. Price data are the monthly average prices of electricity by customer class. Income data are yearly per capita personal income by county. These county income data are then associated to the relevant utility service territory and a subsequent weighted average per capita personal income for each firm is derived. The value of land by county acts as a proxy variable for wealth. A similar procedure to the weighted income variable derivation is used to derive a weighted land price. All economic variables are expressed in real terms, deflated by the Consumer Price Index for urban wage earners.

The weather data are compiled by the seven official U.S. weather stations in Iowa and obtained from the National Climatic Data Center. The relevant variables that are included are temperature, humidity, and wind speed by region. These data are collected at three hour intervals for each day of each month of a given year.

A minimum of fourteen years of data exist for each of these variables. However, the price, income, and walth data are not hourly data. The smallest disaggregate time unit is a monthly price unit; income and wealth being yearly measures. Thus, algorithms were derived to reduce the income and wealth variables to monthly observations based on testing the rates of change over the course of the time frame involved and the known rates of change that are disseminated on a periodic basis from the U.S. Department of Labor and the Iowa State University Extension. Simple monthly average values are not the proxies used for these variables. Finally, three qualitative variables or dummy variables to differentiate week days from weekend days and from holidays are also incorporated due to the known differences in load patterns on these days.

The model used in this study is based on hourly cross section and time series pooled data consisting of economic variables, weather related variables, and dummy variables for identifying weekdays, weekends and holidays. The model consists of a set of 24 equations - one for every hour of a day. Thus, each equation in the model represents an hourly demand for electricity. The demand model is specified for an average residential customer; but it can be modified to estimate total demand by all customers of a given utility, as well as, demand at the state level.

The demand for hourly electric consumption by an average individual customer is presented as:

$$E_i = H_i(P_E, Y_k, LV_k, W_{ij}, N, D_t, PI, PO, U_i)$$

where

- E_i is the level of electricity consumption in (kWh) for hour i;
- P_E is the average price of electricity ($/kWh);
- Y_k is the per capita income ($) for the service region k;
- LV_k is the per acre land value for the service region k;
- W_{ij} are the weather variables (j), for the hour i;
- N is the number of customers;
- PI is the Consumers' Price Index (1967=100);
- D_t is the dummy variable (t) representing the day of electricity consumption;
- PO is the average price of related products such as natural gas, fuel oil;
- U_i is the stochastic variable associated with electricity consumption for the hour i;
- H_i is the symbol of the functional relationship for hour i.

i = 1, 2, . . ., 24 hours
j = 1, 2, . . 5, weather variables
k = 1, 2, . . ., 6 service regions
t = 1, 2, 3 dummy variable for weekday, weekend, and holiday

Several forms of demand models and several different demand determining variables were tested.

Forecast Methodology

To this point, a traditional single equation econometric model has been described. The available literature suggests that this strategy has generated forecasts that are met with mixed reviews with respect to the forecasts' accuracy. The load forecast model that is derived from this model, however, is unique. Its singularity lies within the manner in which the weather vector is treated.

Instead of assuming climatic conditions to be average or normal for the load forecasting periods, fourteen years of hourly (*ex post*) time series weather data for individual service area were used to estimate the *ex ante* weather vector and would prevail in the future under the assumptions inherent in this load demand forecasting model. To integrate the weather vector with the economic demand component of the model, a simulation technique was adopted to generate a series of historical (*ex post*) as well as *ex ante* hourly values for each variable in the weather vector: temperature, humidity and wind speed. Since each customer faced a time series of weather conditions, cooling degree hours (for hot temperatures) and heating degree hours (for cold temperatures) were measured for each service area by an iterative procedure similar to one used by the meteriological researchers. Use of cooling and heating degree hours captured more completely the effect of temperature on consumption. Seasonal variations in humidity and wind speed by hour were also included to determine the influence of other climatological factors on the estimated load demand.

In forecasting with an econometric model, forecasts for each of the final explanatory variables (e.g., prices, income, etc.) must first be made. The difficulty of that task depends on individual factors. The projected economic and demographic variables used in this study are based on estimated growth of the future number of customers, rate of inflation, personal income and the future inflation-adjusted prices of the other variables included.

The forecast of hourly load demand was then made by assigning rates of growth for price, income, and wealth based on judicious assessments of staff, from other sources such as the Department of Energy's Energy Information Report to the Congress, and also from forecasts made by other researchers at other state agencies or the universities within the state. Simulations were then run incorporating each of the 14 years of weather such that a distribution of loads for each hour for each day for each month of the forecast year was produced. From those distributions, minimum and maximum hourly forecasts were made with a mean and standard error associated with each using Klein's Tolerance Interval Concept.[2] It is through these distributions that a range of hourly loads was set. To derive the final forecasted load, an adjustment is made to that forecast utilizing the properties of log-normal distributions. This produces the load demand by hour by day by month. Obviously, the maximum load demand for a given month is a peak load for that month.

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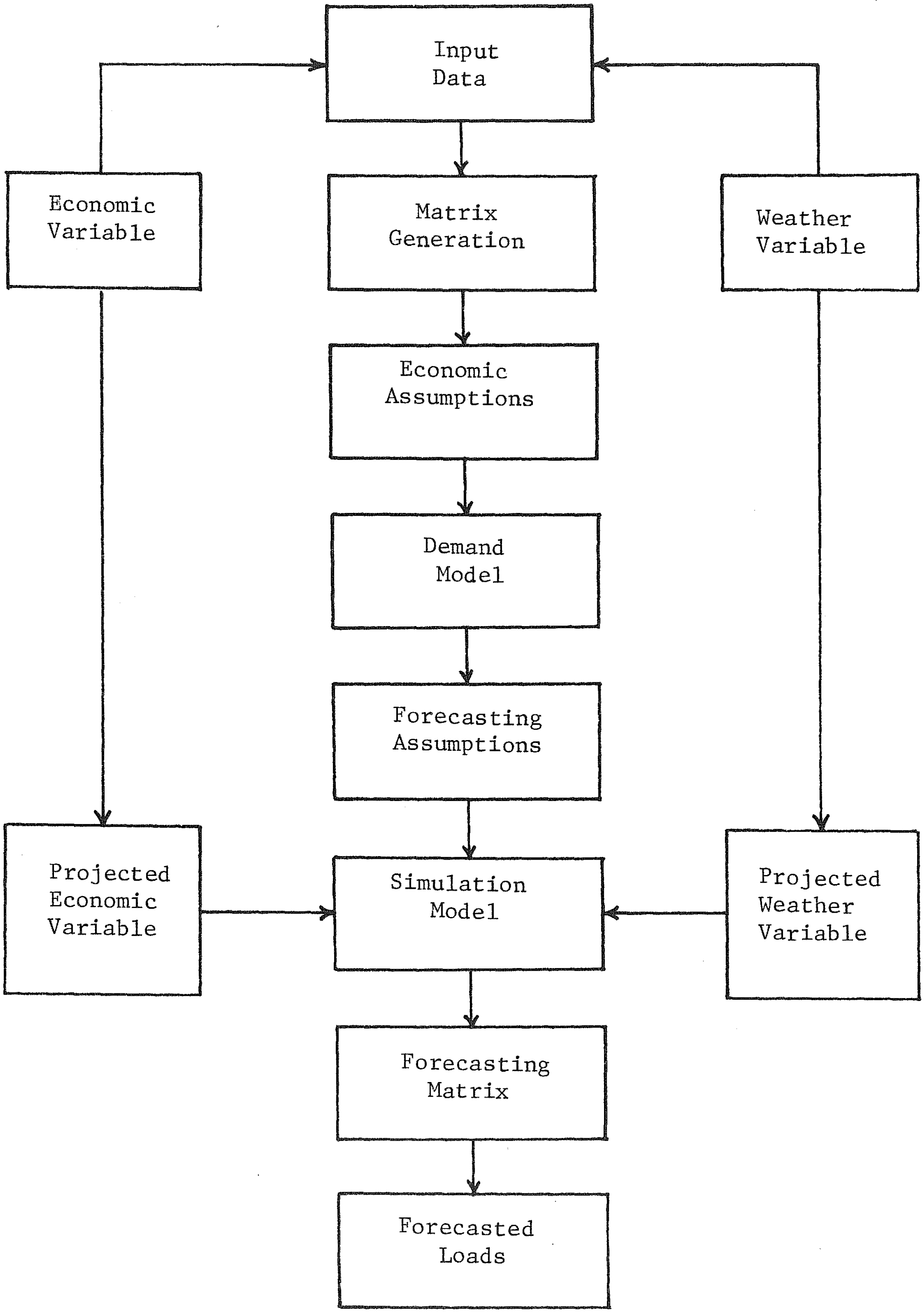
[2] Klein, L.R., *A Text Book of Econometrics*, Row, Peterson and Company, N.Y., 1956, pp. 242-264.



Finally, a schematic diagram of the entire modeling effort and procedure is presented in the above chart.

Results and Discussion

Prior to the forecasting of future demand loads, the estimates of hourly demand equations are derived. As a result of this, a set of own price elasticities, income elasticities, as well as elasticities of other demand determinants are estimated. The usual summary statistics and measures of dispersion indicate the stability and the efficiency of the estimated demand model. The space constraint limits further discussion of this phase of the statistical evaluation of the model.

Figure 1 shows the actual and forecasted summer peak loads for an Iowa utility. In 1982, 936 MW was the actual hourly peak load reported by the company. The model forecast was 933 MW for the hourly summer peak of 1982. The forecasted summer hourly peak loads for 1983 and 1984 are 964 MW and 922 MW respectively, which are very close to the hourly summer peak loads forecasted by the MAPP for this Iowa utility for 1983 and 1984. Table 1 indicates three sets of typical monthly load (MW) forecasts for 1983 and 1984.

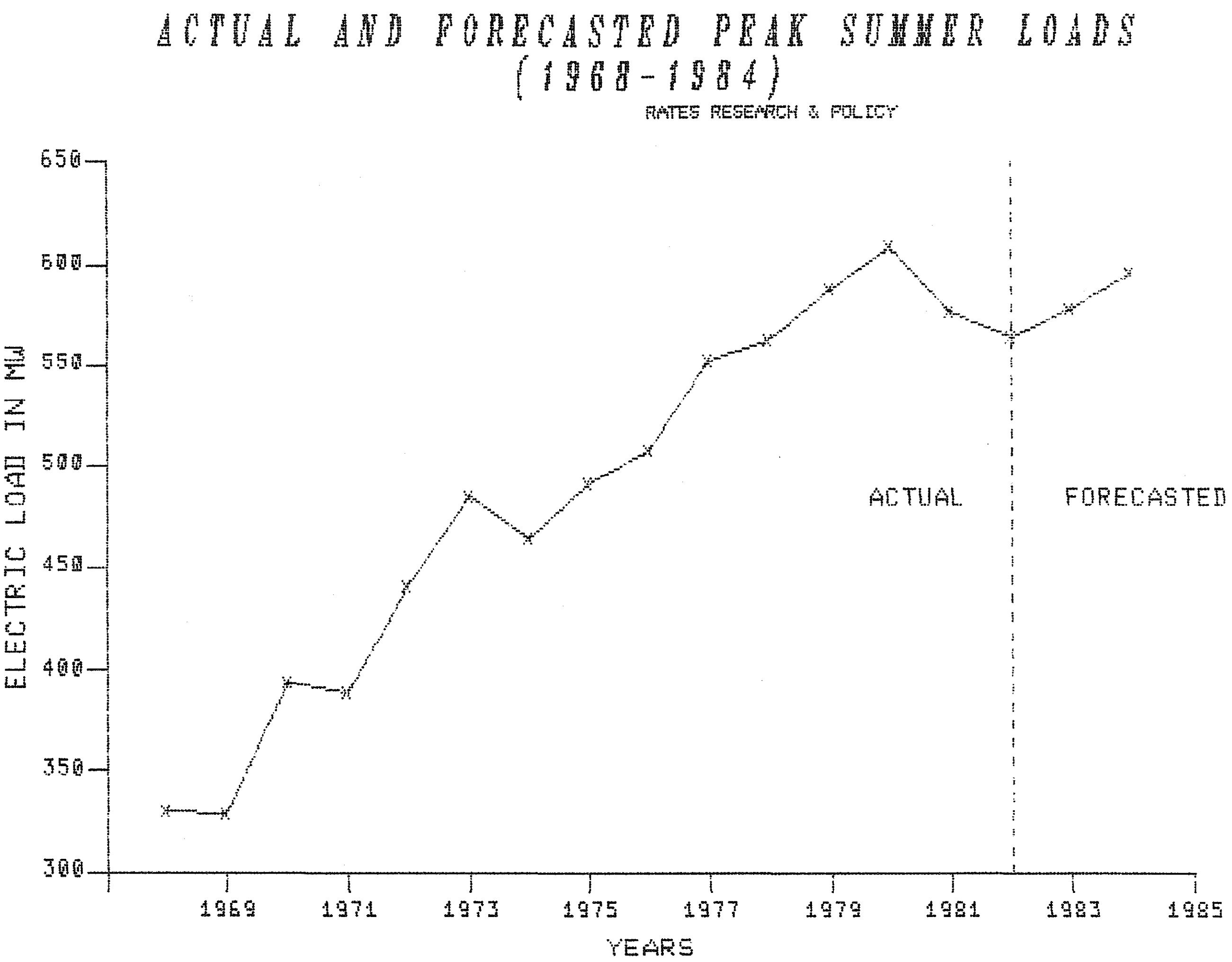
Table 1

Monthly Forecasted Demand for Electricity (MW) by Customer for An Iowa Utility

	1983				1984			
	Min	Mean	Max	C.V. (%)	Min	Mean	Max	C.V. (%)
Jan.	688	709	728	1.7	705	725	745	1.7
Feb.	674	692	708	1.6	693	708	725	1.4
Mar.	664	679	731	2.4	669	699	752	2.4
Apr.	681	745	821	6.0	701	768	845	6.0
May	732	828	889	5.6	754	851	914	5.6
June	839	888	964	4.4	864	914	992	4.4
July	846	905	962	4.4	871	930	991	4.5
Aug.	832	883	952	3.7	855	908	973	3.6
Sept.	752	823	916	6.0	773	847	942	6.0
Oct.	672	735	812	6.7	692	757	835	6.7
Nov.	652	665	692	1.7	672	684	710	1.7
Dec.	666	685	708	1.9	683	702	724	1.8

The coefficients of variation (C.V.) that measure the relative efficiency of mean hourly forecasts with respect to standard deviations are also shown in Table 1 for each month. The coefficients of variation (C.V.) are below 5% for most of the year except April, September and October. One plausible explanation of slightly higher C.V.'s for these months could be that the model is based on the average weather fluctuation over 14 years of hourly observations. Some years, spring and fall climatic conditions might have varied widely and the model did not capture such extreme outliers. Another reason may be due to the assumption of annual growth of customers instead of seasonal growth. However, the dispersion in error variations is well within the statistical range of acceptance. The value of C.V.'s could have been reduced substantially with the consideration of the maximum hourly load forecasts instead of

FIGURE 1



SOURCE: Figure is drawn from an Iowa utility

hourly mean forecasts. The minimum and maximum hourly load forecasts provide a range tolerable within the bounds of acceptable forecasting errors. In Figure 2, the actual monthly loads, and forecasted mean and maximum loads are presented for 1981, depeicting the trends in actual and forecasted loads for analytical comparison.

However, a more relevant test of this model's accuracy is a comparison of the 1983 forecasts for several Iowa utilities and the actual summer peak loads that occurred. It should be pointed as well that the Summer of 1983 in Iowa was the hottest since 1936.

Firm A peaked in July with a load of 785 megawatts. The model's forecast was 0.7% under that actual load. Firm B peaked in mid-August at 964 megawatts. The model's forecast was within 0.4% of the actual. In general, we can say that all peak load forecasts were within 5.0% of the actual peak loads.

Figure 3 reveals the summer peak growth rate of electricity over the last 14 years and forecasted growth rates. Given the current economic environment and a slightly conservative outlook for future economic recovery, 3% annual peak load growth rates are forecasted on the average for the period considered. These forecasted peak growth rates are fairly consistent with the forecasted peak growth for the national level. If, and only if, the economy turns around faster than anticipated, and the ongoing structural changes in the economy are capable of absorbing the shocks quickly, the past relationship between the growth of the nation's GNP and the demand for electricity can be reestablished. Given the socio-economic and industrial environment in Iowa, it is expected that the impact of any potentially rapid growth in Iowa's economy will occur slowly here compared to the heavily industrilized states of the nation.

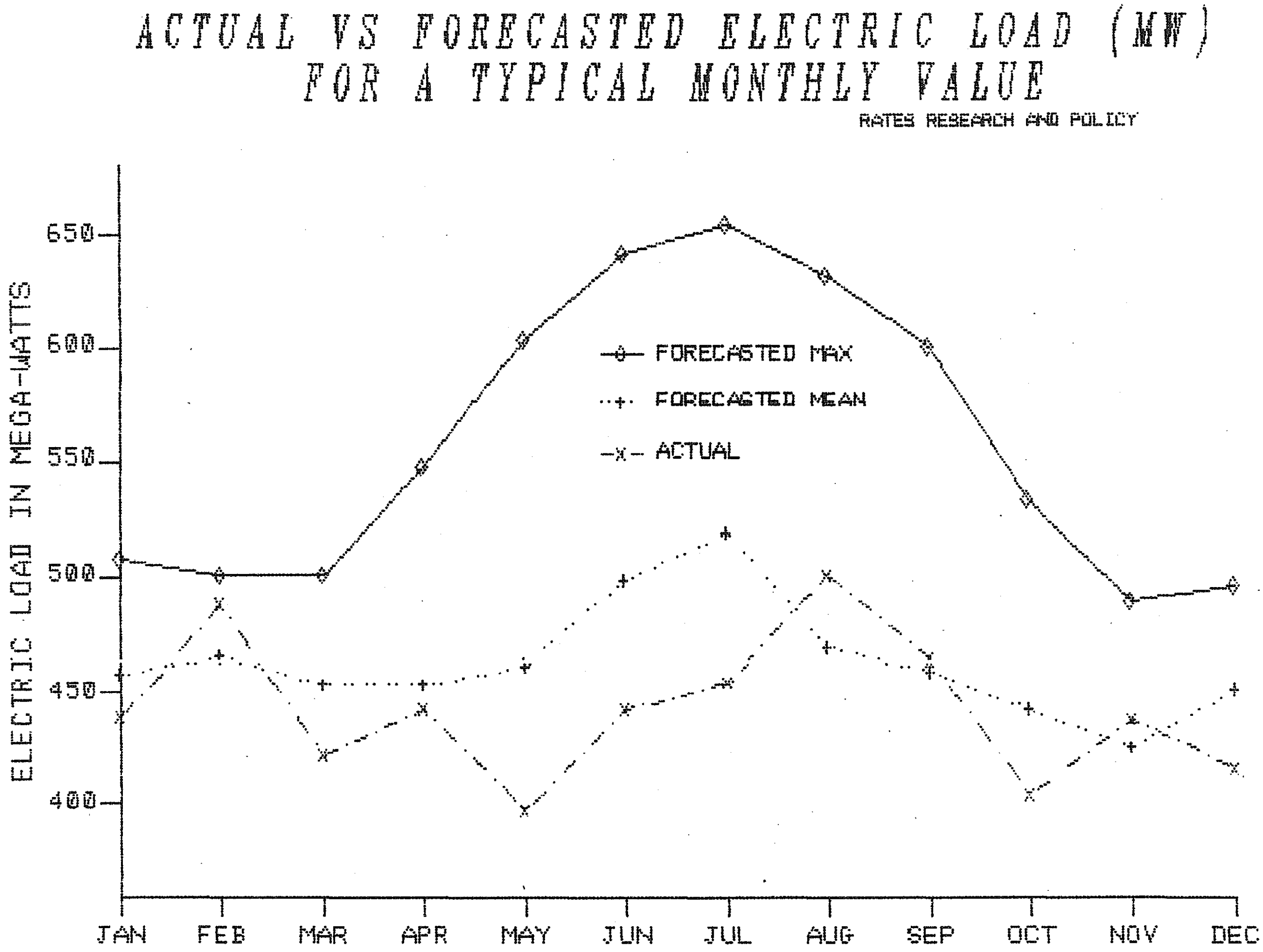
Conclusion

In summary, the power of predictability of the model and the statistical significance of the estimates were tested against other models and estimates. Special considerations were given to the stability and consistency of the model. The demand estimates as well as the forecasted hourly loads obtained by applying this model were checked against the historical trend as well as actual occurrence of loads. The study based on this analytical framework focuses on several empirical issues that have significant policy implication and economic justification.

However, the model serves several important regulatory functions. A definitive set of own price of elasticities of demand for electricity across a 24-hour period for the state of Iowa, for 6 companies has been derived. On balance, discussion of elasticities within the industry and across regulatory commissions have relied upon broadly defined regional and/or national data sets to provide such estimates. This particular set, however, is solely reflective of Iowa behavior.

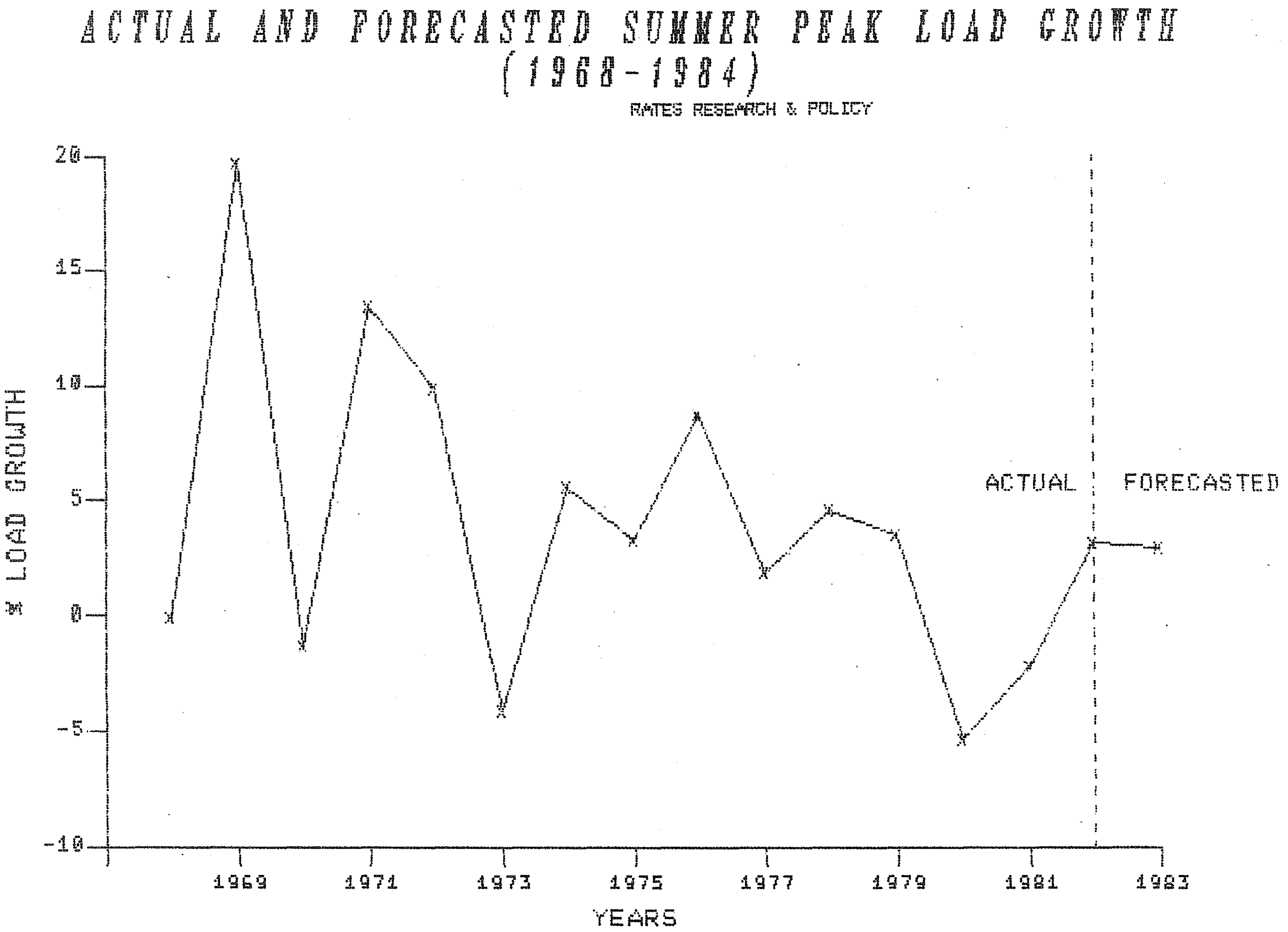
This model of estimating and forecasting hourly load demands offers a method of checking forecasts submitted by the utilities in the periodic reporting process for PURPA cost of service studies, for MAPP membership

FIGURE 2



SOURCE: Figure is drawn from an Iowa utility

FIGURE 3



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requirements, and regulatory monitoring functions. Prior to this model, it is believed that a comprehensive model of this magnitude was not available to Commission staff for such uses.

Finally, this model offers the opportunity for adaptation and modification when the necessity for such change arises, without having to totally reconstruct the model or respecify the basic econometric relationship. It is a model of substantial foundation within economics, mathematics, and statistics.

FORECAST FEEDBACK ANALYSIS (FFBA)

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I. Introduction

An anonymous old sage has said: "The only thing we learn from history is that we do not learn from history." Could this also be true of electric utility load/energy forecasting? Do we place enough emphasis upon "feedback", i.e., do we systematically compare the forecasts with what actually occurred? Do we attempt to learn from such a comparision, thereby improving our forecasting capability?

This paper presents one of a number of possible approaches to Forecast Feedback Analysis (FFBA); however, it is not intended to be a critique of any individual modeling program. This example of FFBA consists of: a) load forecasts by a group of four utilities, and b) this author's adjustment to those forecasts, based upon the historical forecast accuracy for those utilities. It shows the methodology for determining the historical accuracy and adjusting the utilities' forecasts. The combined difference between the utilities' forecast 1990 surplus and their adjusted 1990 surplus is over 3,000 MW, or $3 to $6 billion of rate base. These numbers are presented, not as a bona fide "proof" of forecast error, but as an illustration of "what we need to learn from history."

II. Feedback Analysis

Feedback, a term dating back to the vacuum tube electronics field, refers to our comparing the last 8 years' forecast values (or whatever other data base may be used) with the last 8 years' actual experience --- one might look at it as developing a forecaster's "batting average." Forecast Feedback Analysis (FFBA) can evaluate not only the overall forecast accuracy history (the team batting average), but also the forecast accuracy history for a variety of loads (the individuals' batting averages, if necessary). Carried out to completion, it can show whether the forecast error is due to erroneous assumptions upon which the model is designed (for example, market sensitivity assumptions) or erroneous data forecasts used in the model (for example, inflation rate). It can also reveal whether an on-target forecast was merely good luck or was good data and good forecast model. Figure 1 is a diagrammatic presentation of this feedback process. If we do not try to "learn from history, we will not learn from history."

III. <u>Example</u>

The example below illustrates the process by which FFBA can provide "batting average" data. It uses the following process:

a) Obtain the last X-number of years of forecasts.

b) Prepare a forecast/actual chart as shown below:

TABLE OF FORECASTS
VS.
ACTUALS
(Using Hypothetical Data)

Actuals		Forecast Values of Actuals Made in Years:				
Year Occurred	Value	1981	1980	1979	1978	1977
1982	100	105	110	115	120	115
1981	95		98	102	100	106
1980	90			93	89	97
1979	85				89	89
1978	80					85

c) Prepare a chart similar to the one above, except showing % error.

d) Tabulate all the % errors for one-year-ahead forecasts, two-years-ahead forecasts, etc., as follows:

TABLE OF PERCENT ERRORS
VS.
FORECAST YEARS AHEAD
(Using Hypothetical Data)

One-Year-Ahead Forecasts		Two Years-Ahead Forecasts		Three-Years-Ahead Forecasts		Four-Years-Ahead Forecasts	
Years	% error	Years	% error	Years	% error	Years	% error
81 for 82	5.0%	80 for 82	10.0%	79 for 82	15.0%	78 for 82	20.0%
80 for 81	3.2%	79 for 81	7.4%	78 for 81	5.3%	77 for 81	6.3%
79 for 80	3.3%	78 for 80	- 1.1%	77 for 80	7.8%	average	+13.16%
78 for 79	4.7%	77 for 79	4.7%	average	+ 9.35%		
77 for 78	6.3%	Average	+ 6.99%				
average	+1.25%						

d) Prepare a graph showing the above results. These are shown in Figures 2-7.

e) Prepare a "Y-year" rolling band analysis to see if the "batting average" is improving. Three-year rolling band comparisons are also shown in Figures 2-7.

f) Prepare an error distribution graph that includes a comparison of each forecast/actual pair of data. These graphs are also shown in Figures 2-7.

g) Compare the utilities' actual forecasts with their actual experience, adjusted to account for the historical forecast "batting averages" of each utility. The following formula is presented to illustrate the logic of the comparison:

$$AF_{(1982 + N)} = UF_{(1982 + N)} (100 - AHFE_{(N)}) / 100$$

Where AF = adjusted forecasts
UF = utilities' forecasts
AHFE = average historical forecast error (% high)
N = years-ahead

The actual formula used in this paper was somewhat more complex, taking into account (but not adjusting) the forecasts of purchases, sales, generating capacity, and "reserve capacity obligation." The results of this comparison are shown in Figure 8.

The farthest year in advance uses only one historical data point. A year earlier uses two data points. Two years earlier uses three data points, etc. Changes in the modeling technique will, of course, affect the Forecast Feedback Analysis; however, one of the goals of the analysis is to test the "batting average" of the new modeling technique.

No one can create a simplistic "cook book recipe" for a Forecast Feedback Analysis (FFBA) as the above example could imply. Each situation may require a somewhat different approach. The above examples, however, illustrate the steps this author has taken in an FFBA and presents "ingredients for the recipe" that must be adjusted to the individual problem at hand. It should be borne in mind that the FFBA is only an indication of forecasting capability -- it is not an accurate "proof" of what a forecast should be. Just as forecast conclusions become less and less accurate the longer in advance the forecast is made, so does the FFBA. The FFBA must be used with discretion to accomplish its goal: to help us "learn from history"--to search for and improve our weakest points in load/energy forecasting.

V. Recommendation

It is the author's personal recommendation that utilities and regulators jointly develop techniques to provide meaningful comparisions of load/energy forecasts with what actually occurred. These techniques should highlight the segments of forecasting that necessitate the greatest ongoing study for improvement as well as the segments that necessitate the least future attention. These techniques should include:

1. Methods of identifying the accurate and the inaccurate modules of the forecast model. It will then be possible to keep the accurate modules intact and to search for the causes of, and improvements for, the inaccurate modules of the forecast model. In this process, it is necessary to clearly distinguish between inaccuracies caused by the modeling technique/assumptions and inaccuracies caused by the data/assumptions that are inputs to the model.

2. Methods of identifying data items and data forecasts that are historically correct or non-sensitive and identifying those that are historically in need of improvement.

3. Methods of keeping and using records to facilitate the above. For example, consider a hypothetical record of the load forecast of the 1982 commercial peak load of an electric utility:

TABLE OF FORECAST ASSUMPTIONS
VS.
ACTUAL EXPERIENCE

Parameters	Values Actually Occuring in 1982	Values used when forecast was made (N) (in Year N)			
		N = 1981 Forecast of 1982 Values	N = 1980 Forecast of 1982 Values	N = 1979 Forecast of 1982 Values	Etc.
Inflation	______	______	______	______	______
Cost of living	______	______	______	______	______
GNP	______	______	______	______	______
Population	______	______	______	______	______
etc.	______	______	______	______	______
MWH Energy Sales	______	______*	______*	______*	______*
MW peak load	______	______*	______*	______*	______*

* Determine the peak load and energy sales that would have been forecast in year N for 1982 if the actual 1982 parameters had been used in the year N forecast model.

4. Methods of presenting the results of the Forecast Feedback Analysis in an easily used format.

Finally, the Forecast Feedback Analysis must be tailored to accomplish the job at hand. It can then be used to prove wrong the anonymous old sage, quoted at the beginning of this paper. Using the FFBA, we can indeed "learn from history."

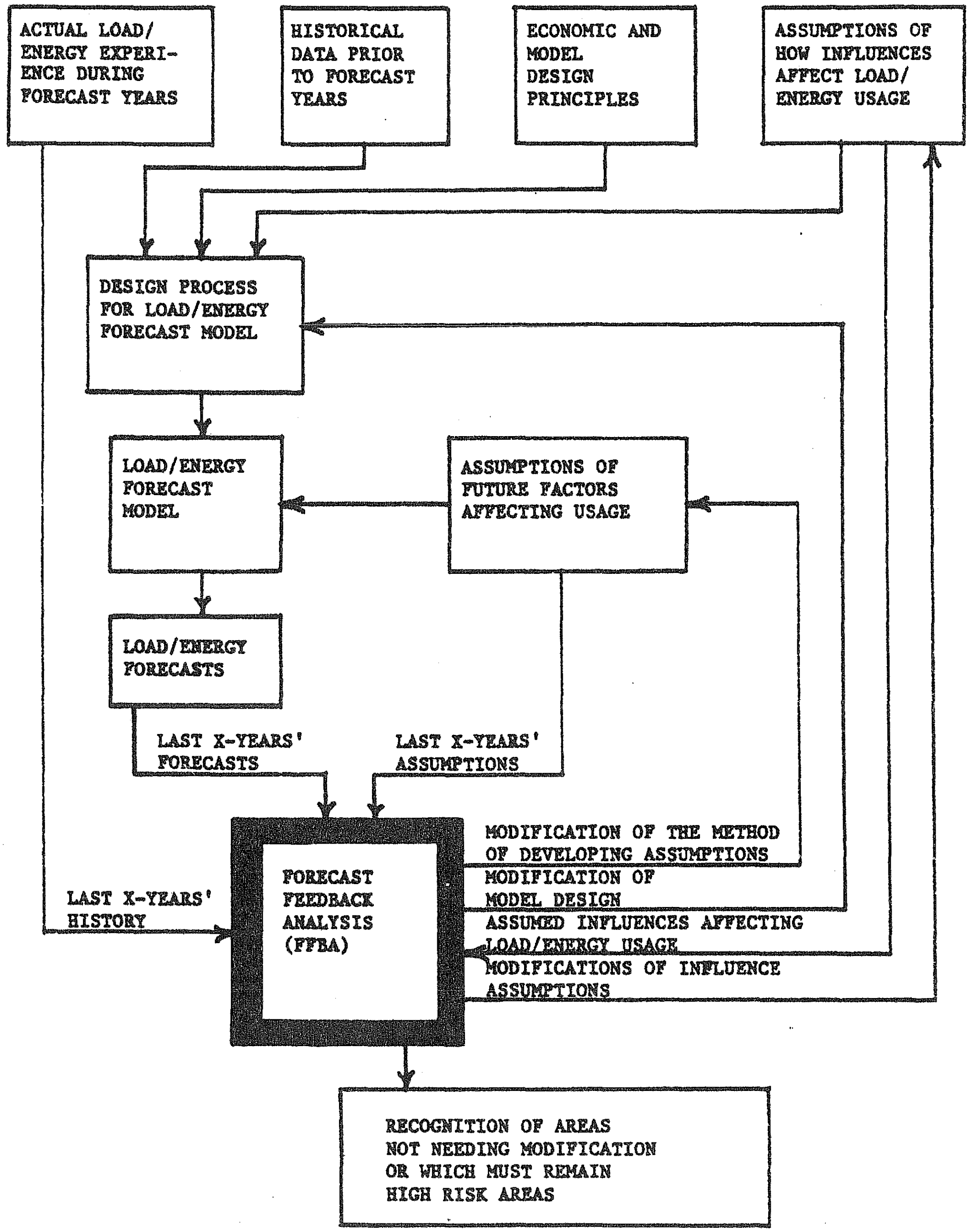


FIGURE 1--FORECAST FEEDBACK ANALYSIS PROCESS

HISTORICAL RECORD OF FORECAST ACCURACY

These data are based upon forecasts submitted 1973-1980 for the 1974-1981 loads. The 8-year experience shown on the forecast graphs represents one forecast. The 7-year experience is the average of 2 forecasts; (etc.) and the 1-year experience is the average of 8 forecasts.
——— = winter and - - - - - = summer.

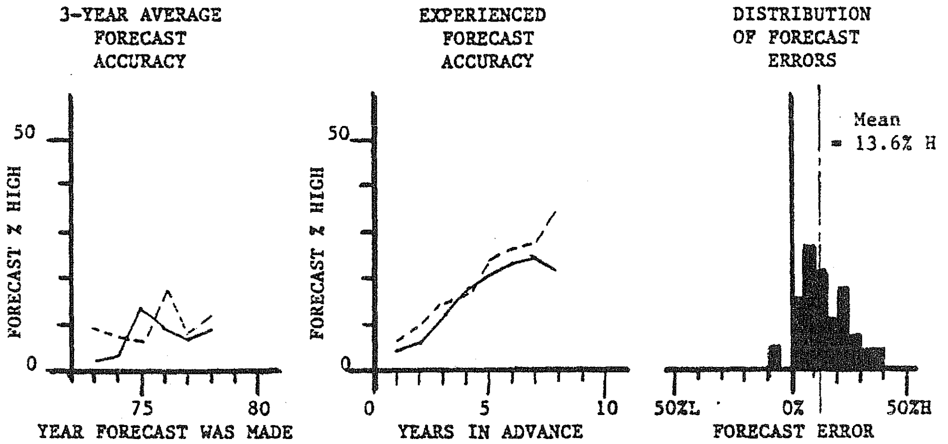


FIGURE 2 - FORECAST ACCURACY FOR UTILITIES A, B, C, & D

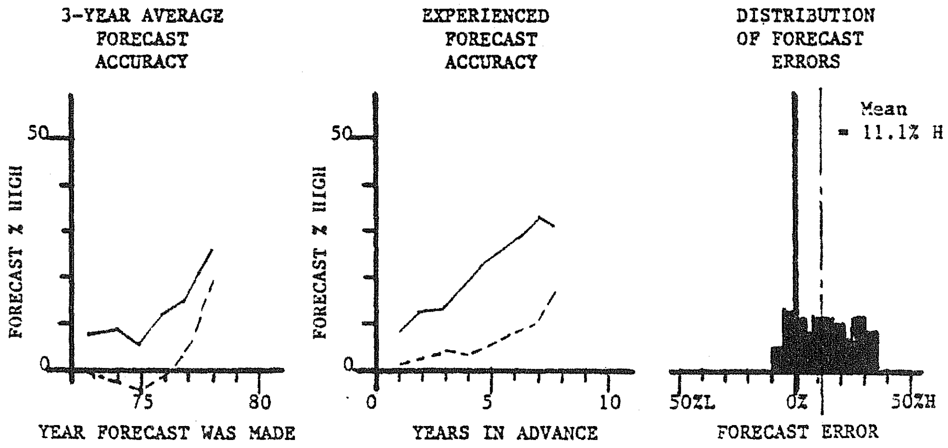


FIGURE 3 - FORECAST ACCURACY FOR UTILITY A

HISTORICAL RECORD OF FORECAST ACCURACY

These data are based upon forecasts submitted 1973-1980 for the 1974-1981 loads. The 8-year experience shown on the forecast graphs represents one forecast. The 7-year experience is the average of 2 forecasts; (etc.) and the 1-year experience is the average of 8 forecasts.
——— = winter and - - - - - = summer.

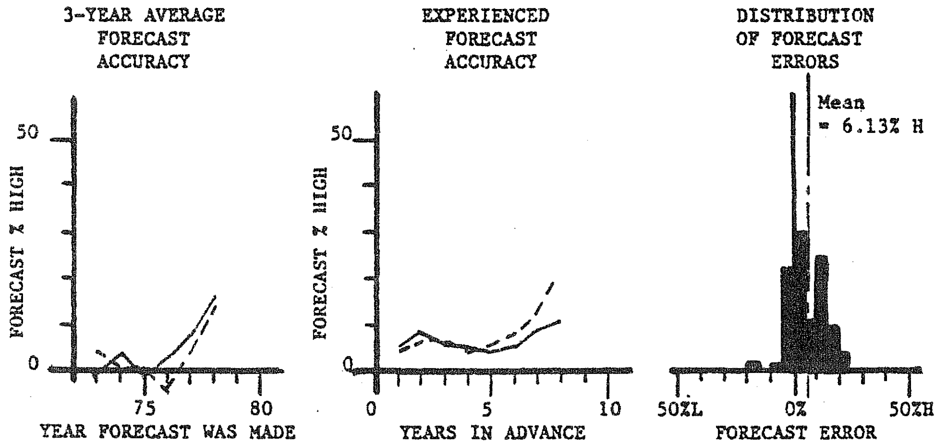


FIGURE 4 - FORECAST ACCURACY FOR UTILITY B

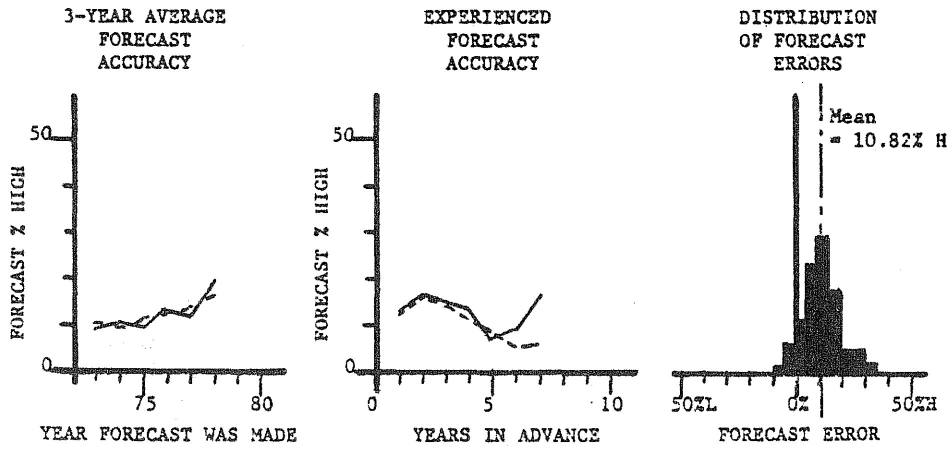


FIGURE 5 - FORECAST ACCURACY FOR UTILITY C

HISTORICAL RECORD OF FORECAST ACCURACY

These data are based upon forecasts submitted 1973-1980 for the 1974-1981 loads. The 8-year experience shown on the forecast graphs represents one forecast. The 7-year experience is the average of 2 forecasts; (etc.) and the 1-year experience is the average of 8 forecasts.
——— = winter and - - - - - - = summer.

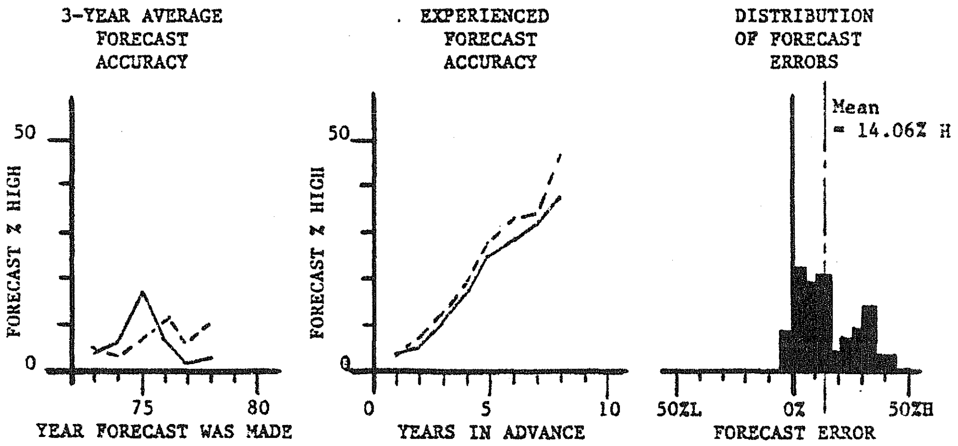


FIGURE 6 - FORECAST ACCURACY FOR UTILITY D

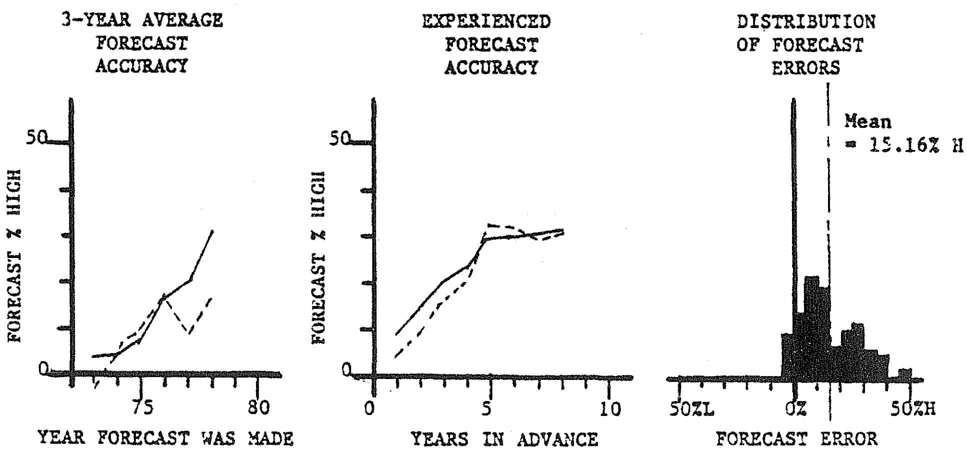


FIGURE 7 - FORECAST ACCURACY FOR UTILITY E

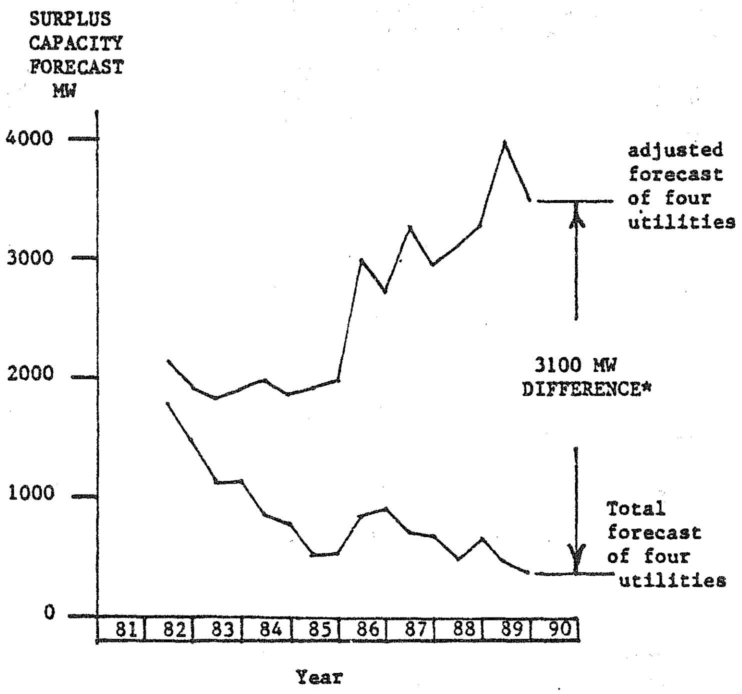


FIGURE 8 - Comparison of surplus capacity forecasts of four utilities with adjusted forecasts based on each utility's history of forecast accuracy. (This comparison took into account "reserve capacity obligation," but did not adjust purchases or sales.)

*See caveat on page 4, third paragraph

LONG TERM FORECASTING OF ELECTRIC LOAD WITHIN OVERALL ENERGY DEMAND BY THE USE OF THE COMBINED MAED AND WASP METHODOLOGIES

by: J. P. Charpentier and P. E. Molina
International Atomic Energy Agency (IAEA)

In meeting its objective to assist its developing Member States in the peaceful uses of nuclear energy, the IAEA conducts an extensive programme of work in nuclear power planning and implementation, including economic assessment to determine the appropriate role of nuclear energy within the national energy plan of developing Member States. Within this framework, the IAEA has developed appropriate methodologies specifically adapted to developing countries and has used them to carry out energy and nuclear power planning studies in co-operation with requesting Member States.

The WASP methodology for electric generation expansion planning had been traditionally used by the IAEA for carrying out global studies such as the Market Survey for Nuclear Power in Developing Countries (1972-1973) or, at special request of some of its Member States, individual Nuclear Power Planning Studies (NPPS) for the respective country or region within the country.

Although the WASP methodology has been recognized as suitable for carrying out NPPS, IAEA experience in these studies showed that the projections of electricity demand were, in some cases, not well grounded.

In fact, the projected future demand for electricity, in terms of both electrical power and energy requirements, is one of the most important factors determining the need for additional capacity and/or energy, and consequently the need for nuclear power. Experience showed that the electricity demand forecasts supplied by developing countries often were not developed in a systematic procedure which would ensure internal consistency with their main economic and industrial development objectives and possibilities. Thus, the electricity demand projections often proved to be a weak point in the resulting estimates of the role of nuclear power in the country's energy supply.

To improve the estimates of future electrical energy requirements, the IAEA in collaboration with the Institute for Economic and Legal Aspects of Energy (IEJE, Grenoble, France) and the International Institute for Applied System Analysis (IIASA, Laxenburg, Austria) developed a computer model named MAED (Model for Analysis of Energy Demand). This model is used by the IAEA to develop coherent projections of future energy and electricity needs, within the framework of an Energy and Nuclear Power Planning Study (ENPPS) for requesting Member States. The first such study was conducted for Algeria in close co-operation with the Societe Nationale de l'Electricite et du Gaz d'Algerie (SONELGAZ).

This paper describes the methodologies involved in carrying out an ENPPS, with emphasis on the MAED Model. The necessary steps for successful conduction of such a study are also outlined. The advantages of using such an approach will be described with reference to the Algerian study.

1.0 Introduction

In meeting its objective to assist its developing Member States in the peaceful uses of nuclear energy, the International Atomic Energy Agency (IAEA) conducts an extensive programme of work in nuclear power planning and implementation, including: a) economic assessments to determine the appropriate role of nuclear energy within the national energy plan of developing Member States, b) assessment of the impact of introducing nuclear power in a developing country in terms of financing, manpower, infrastructure requirements and possibilities, and finally c) once the country has decided to go nuclear, technical assistance in all the steps necessary to implement the resulting programme.

Obviously, all aspects listed above require careful analysis and appropriate timing in order to guarantee the succesful introduction of nuclear power in a given country. Further, detailed description of all Agency activities in these fields would be rather cumbersome and well beyond the scope of this Symposium. Therefore, the description which follows emphasizes on the economic assessments mentioned in a) above.

These assessments involve three major types of interdependent and closely related activities: a) the development of appropriate methodologies specifically adapted to developing countries; b) the conduct of training courses on energy and nuclear power planning techniques, including use of methodologies developed by the Agency; c) and the carrying out of energy and nuclear power planning studies in co-operation with requesting Member States. Within this framework, close co-operation with other international organizations have been established, including in particular, the World Bank (IBRD) in joint IAEA/IBRD electric power sector assessment missions to developing countries.

1.1. Development of methodologies

Electricity planning and particularly, planning of expansion of electric power generating systems has followed a well known course leading to the present situation in which various types and sizes of generating units, including nuclear, can be used and the decision to add any of these units into the system requires first, an assessment of the economic impact of this addition on the existing generating units and on future additions and second, economic comparison against alternative expansion strategies. In modern power systems, execution of these tasks normally requires the use of sophisticated computer programs which include algorithms permitting simulation of the system operation for the proposed expansion strategies and economic comparison of cost streams extending over time.

Recognition of this situation, led to the development of the WASP computer model and of a methodology [Ref. 1] for the analysis of the expansion of electric power generating systems, as described in Section 2.0, which was first used by the Agency during the "Market Survey for Nuclear Power in Developing Countries" (1972-1973) [Ref. 2]. Improved versions of WASP namely WASP-II and WASP-III have been developed throughout the years and have been used by the Agency to conduct, at special request of some of its Member States, Nuclear Power Planning (NPP) studies for the respective country or region within the country [Ref. 3].

Although the WASP methodology has been recognized as suitable for carrying out NPP studies, some criticisms have been raised to these studies, specially concerning the projections of electricity demand used which were, in some cases, not well grounded.

In fact, part of the main input data required for the execution of a WASP study corresponds to the future projections of the electricity demand in terms of both, electrical power and energy requirements, since these projections are one of the most important determinants of the need for additional capacity and/or energy, and consequently the need for nuclear power.

Until recent years, these projections had been usually determined by means of econometric models, ranging from simple extrapolations of historical trends to the more sophisticated techniques including correlation of the energy demand to macro-economic indices of the country's economic standing such as the GDP (Gross Domestic Product) or the GNP (Gross National Product).

However, simple or sophisticated, all these models were based on the search of an invariant parameter to be related to the energy demand, and the link between both was supposed to be a constant or of universal nature, or both at the same time. The well-known AOKI method [Ref. 3] is a good illustration of this point: AOKI is based on a correlation between electricity consumption and GDP per capita determined from historical data gathered from 101 countries. From this and using the historical data for a given country, the model proposes standard paths of development for the country.

Although for the execution of WASP studies, the Member States involved were encouraged to provide this own estimations of future electricity demand, sometimes the AOKI method had to be favoured if no other information was available. On the other hand, the energy projections provided by the country were in many cases based on the application of some kind of econometric models.

Experience in the execution of the above studies has led to the following conclusions; particularly applicable to developing countries:

- The future development of the electricity sector in general, and of nuclear power in particular are not autonomous or independent from any other external influence; thus, requiring an appraisal of this development within an overall energy framework which is consistent with the economic and industrial development objectives and possibilities of the country.

- The future electricity requirements of a developing country are not adequately calculated by econometric models as those above mentioned.

To improve the estimates of future electricity requirements, the IAEA developed a computer model called MAED (Model for Analysis of Energy Demand) [Ref. 4]. This model described in Section 2 is now used by the Agency to develop coherent projections of future energy and electricity demand, and in conjunction with the WASP methodology, permits the execution of energy and nuclear power planning (ENPP) study for developing Member States as described in 1.3 and in Ref. [5].

It is worth noting that in the development of these computer codes, a great effort has been made at the IAEA in order to adapt them to the appropriate conditions of developing countries, not only in terms of the modelling techniques used but also in the design of each program so as to facilitate its transfer to interested Member States. In fact, all programs above mentioned may be released by the IAEA to its Member States under certain conditions which in general aim at the non-commerciality of their use.

1.2 Training Courses: To develop expertise in the Member States to enable them to do their own demand forecasting and supply planning, within its annual programme of training courses, the Agency conducts two courses which train specialists from developing Member States in the techniques for energy demand analysis and electric system expansion planning.

The major objective of the training course on "Energy Planning in Developing Countries with Special Attention to Nuclear Energy" is to familiarize energy specialists in developing countries with the fundamental elements of comprehensive national energy planning. The course emphasizes in understanding of the appropriate role for nuclear energy, and aims at improving the country's ability to make a careful and objective choice among the various available energy options, including nuclear.

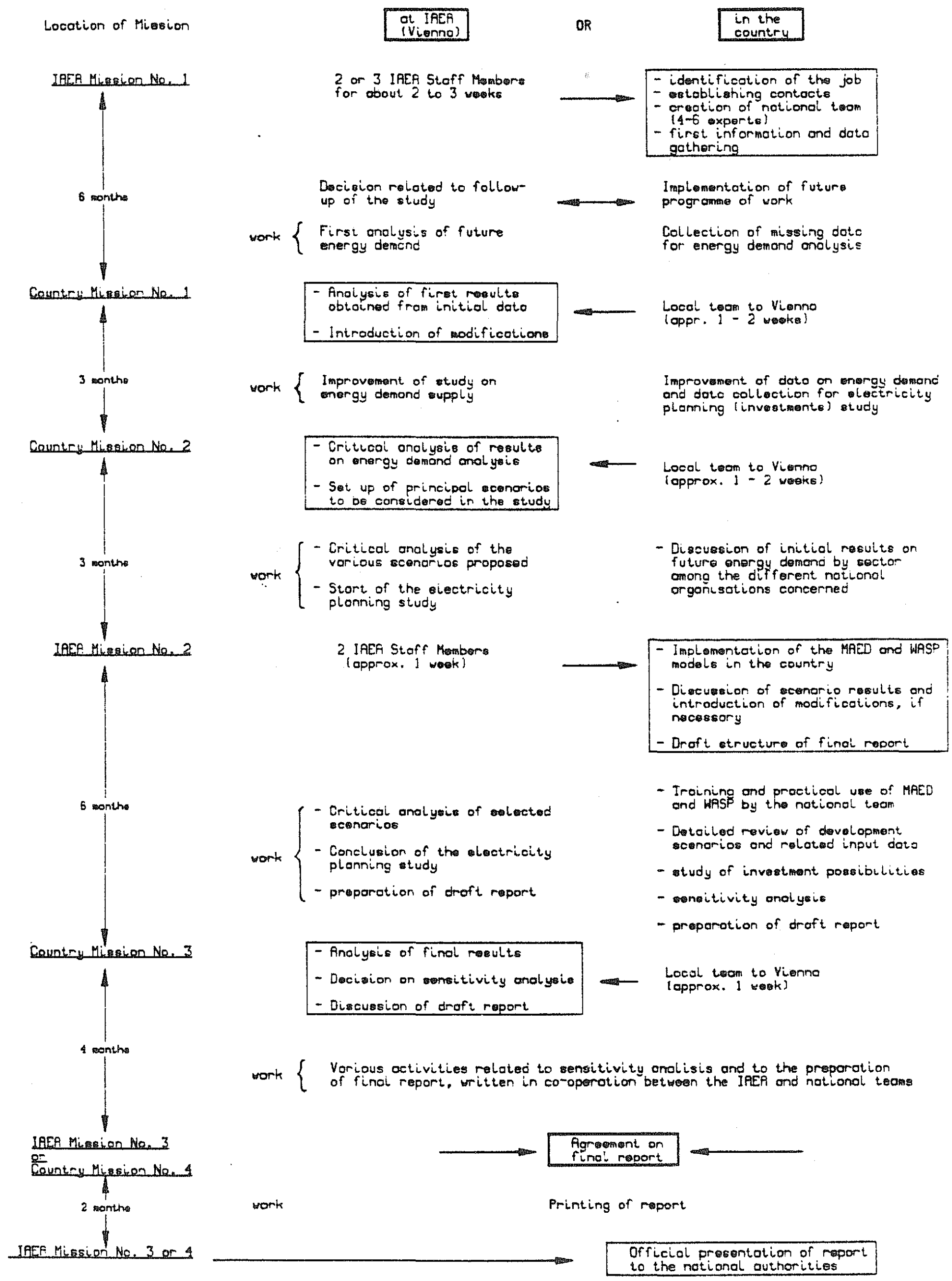
The IAEA training course on "Electric System Expansion Planning" has the objective to train specialists in planning the expansion of an electric generation system; it emphasizes in the use of the WASP model for carrying out this type of planning. Also, emphasis is given to the fact that the WASP study is only part of an overall decision process which should also include considerations on aspects such as transmission requirements, financial and manpower constraints, etc.

1.3 Execution of Energy and Nuclear Power Planning (ENPP) studies: An ENPP study is initiated only upon official request by an IAEA Member State and is carried out as a joint project of the Agency and the Member State. The objective is to assist the Member State in detailed economic analyses and planning studies to determine the need and appropriate role of nuclear energy within its national energy plan consistent with the country's plans for socio-economic and technical development. This requires assessment in terms of economic plans, and economic comparison with alternative energy sources. The analytical methodologies mentioned previously (MAED and WASP) are used during the studies, with improvements and changes as necessary, and are released to the country at the end of the study.

As such studies are carried out in close co-operation with the Member States, a joint team of specialists in energy planning is established. Each joint team includes two or three IAEA staff members familiar with all questions related to energy and electricity planning and the different models which could be used. It also includes a team of specialists from the Member State, in particular, at least five or six engineers and economists well acquainted with the electricty and energy situation in their country. (It is recommended that most of them should have attended the two training courses previously described). Among the national specialists is a senior co-ordinator who can contribute effectively to the work required and who is responsible for making contacts with different organizations within his country in order to obtain the information and data needed for the study. During the execution of

Figure 1

Co-operative working schedule for Executing Energy and Nuclear Power Planning Studies



Total duration: 24 months, including: 3 to 4 IAEA missions of about 1 to 2 weeks
3 to 4 country missions of about 1 to 2 weeks

the study, appropriate training in the use of the planning tools above mentioned is given to the national team, with the objective that further energy and electricity planning studies can be carried out by the country experts.

An ENPP study requires about two years of team-work. Although members of the joint team need not dedicate full time to this activity, the time-period normally cannot be shortened, since it is mainly dictated by the time needed for data and information gathering. Although the exact content, scope and schedule for an ENPP study will vary depending on the Member States, conducting a study involves a well-established procedure. This is outlined in Figure 1 and described in detail in Ref. [5].

A first ENPP study was conducted for Algeria in 1980-1982 [Ref. 6] as described in the following sections.

2.0 IAEA Methodology for Energy and Electricity Planning

Estimating future electrical energy needs

The MAED (Model for Analysis of Energy Demand) is a simulation model designed to evaluate medium and long-term demand for energy in a country (or in a region). MAED was developed by the IAEA working in collaboration with the Institute for Economic and Legal Aspects of Energy (IEJE, Grenoble, France), the International Institute for Applied Systems Analysis (IIASA, Laxenburg, Austria) and the Electricite de France (EDF) Ref. [4]. It is based on experience with an existing model called MEDEE (Modele d'Evolution de la Demande d'Energie). Development was begun in 1980 and completed during 1981.

The MAED model, outlined in Figure 2 provides a flexible simulation framework for exploring the influence of social, economic, technological and policy changes on the long-term evolution of energy demand. To facilitate its application with the more limited data based which is typical of developing countries, it is somewhat simpler than MEDEE.

In order to analyse the energy demand of a given country, the economy is subdivided into the major economic sectors (household, transport, industry, agriculture services), and the energy needs of each sector are subdivided into various elementary needs of useful and final energy (needs for space heating, cooking, furnaces, inter-city transport, and so forth).

The useful and final energy requirements are described by two types of parameters: one linked to technical considerations (such as the efficiency of different appliances) and the other linked to life-style considerations (e.g. average distance travelled by car during a year, size of dwelling etc.).

Special emphasis is given to the forecast of electricity demand, not only in terms of total annual requirements as for other forms of energy but also in terms of the hour-by-hour distribution of power demand during the year.

Figure 3 Schematic representation of the calculations performed by means of Modules 2 and 3 of MAED

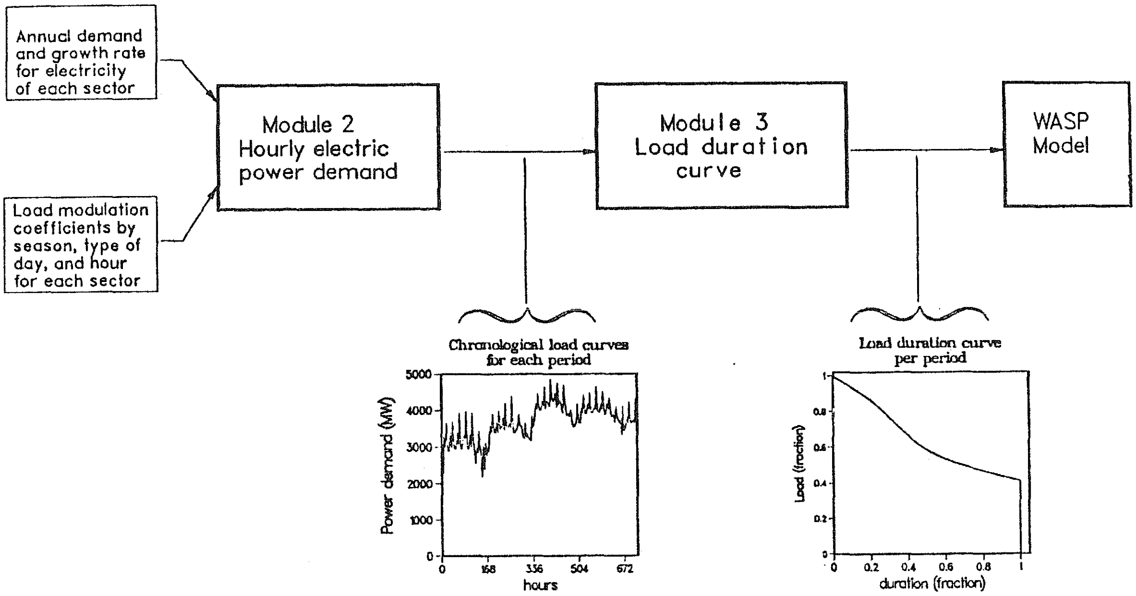
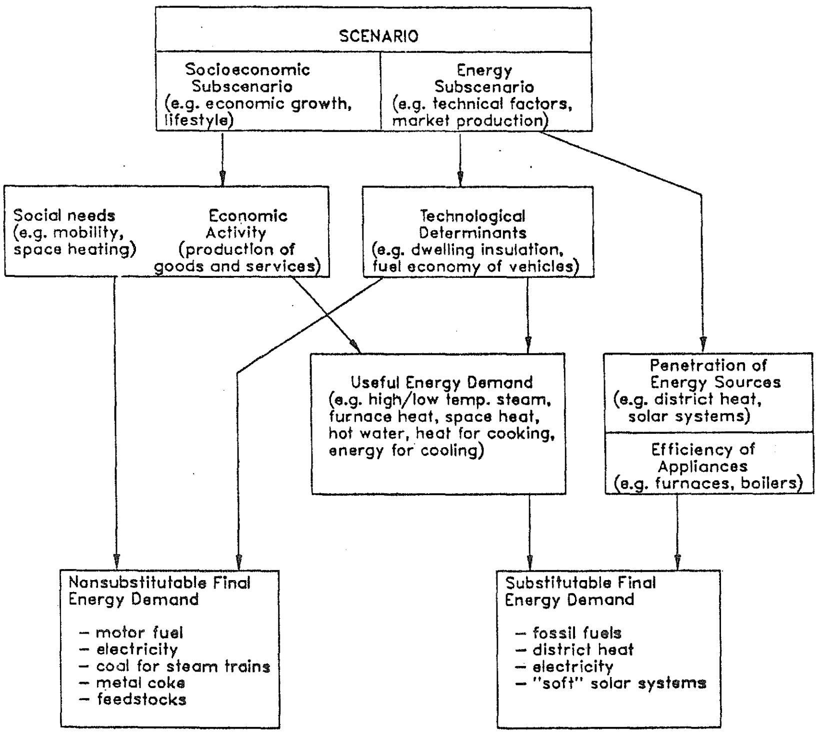


Figure 2 Module 1 of MAED. Scheme for projecting useful and final energy demand



The MAED approach involves the following steps:

- A systematic analysis of the social, economic and technological system in order to identify the major factors determining the long-term energy demand evolution;

- Disaggregation of the total energy demand into numerous end-use categories. The selection of the categories to be considered depends upon the objectives of the analyst and on the availability of data;

- Organization of all determinants into a multi-level structure, from the macro to the micro level, showing how the "macro-determinants" affect each end-use category;

- Construction of a simulation model by simplifying the system structure and grouping the determinants into exogenous determinants and scenario elements. The exogenous determinants encompass those factors for which the evolution is difficult to model (e.g. population growth, number of persons per household), but for which long-term evolution can be adjusted suitably from past trends or from other studies such as demographic studies. The determinants chosen as scenario elements are those for which the evolution cannot be extrapolated from past trends because of possible structural changes in the energy demand growth pattern. Policy factors are an example.

Analysing the economics of system expansion

The WASP [Wien (Vienna) Automatic System Planning Package] model is a system of computer programs using dynamic programming techniques for economic optimization in electric system expansion planning (ESEP). It may be taken as an example of a supply model, whereas MAED is a demand model. The WASP model was developed for the Agency by the US Tennessee Valley Authority (TVA) and was first used during the "Market Survey for Nuclear Power in Developing Countries" (1972-1973). With further assistance from the TVA and the US Oak Ridge National Laboratory, it was improved in 1976 to the WASP-II version which has been widely used by the Agency and Member States. A joint effort of the United Nations Economic Commission for Latin America (ECLA) and the IAEA developed the WASP-III version which was completed in 1980. This latest version of the WASP model was designed to meet the needs of ECLA to study the inter-connection of the electrical grids of six Central American countries where large potential hydroelectric resources exist.

The WASP model is structured in a flexible, modular system which can treat the following interconnected parameters in an evaluation: load forecast characteristics (electric energy forecast, power generation system development); power plant operating and fuel costs; power plant capital costs; power plant technical parameters; power supply reliability criteria; and power generation system operation practices.

The electric energy forecast is obtained through use of MAED as described previously. In addition to the total annual demand for electricity, MAED provides WASP with some essential details about the estimated time distribution of the demand, that is, a "load duration curve", as indicated in Figure 3.

The WASP model is composed of six principal modules. One of these module is used to describe the seasonal characteristics of the electrical loads for each year of study. The second module describes the existing power system and all plants which have been scheduled for commissioning or retirement. The third program describes the alternative plants which could be used to expand the power system (plant 'candidates'). With a fourth program one can generate alternative expansion configurations [a configuration is a set of power plants which meets the electrical capacity requirements of the power system]. A fifth program is used to siumulate system operation with any new configuration. Using a probabilistic simulation model, expected energy generation by each plant and the corresponding operation cost can then be calculated. The reliability of the generating system and the probable amount of unsupplied energy are also estimated. A sixth program is used to calculate the lowest-cost expansion schedule for adding new units to the system over the period of interest, using the data files created by the other modules together with economic inputs and reliability criteria. The objective function of this dynamic programming optimization is the present-worth discounted value of operating costs (including fuel) plus capital investment costs, plus a penalty cost for energy not served, minus a salvage-value credit for plant economic life remaining at the planning horizon.

3. Organization of the ENPP study for Algeria

The organization of this study followed quite closely the schedule outlined in Figure 1: The first IAEA mission to Algeria took place in 1980. It consisted of three experts who stayed in the country for two weeks, with the purpose of investigating the possibilities of undertaking a study on the role of nuclear energy in supplying part of electricity that Algeria will require in the next decades.

As a result of this first mission, a joint team of IAEA and Algeria experts was created composed of two IAEA experts and five Algerian specialists, all staff of the Societe Nationale d'Electricite et du Gaz (SONELGAZ); the company which was assigned full responsibility for the study by the Algerian authorities. Close co-operation between both teams was maintained and several missions of IAEA experts to Algeria and SONELGAZ experts to Vienna were undertaken during the execution of the study.

If the date of the first Agency's mission is taken as the starting date for the study, the latter will have taken two years. During this time the total manpower requirement accumulated to 6-8 man-years without taking into account the contribution from many staff in several Algerian organizations who supplied useful information and data for the study and the development of the computer codes which was carried out in the Agency.

3.1 Purposes and Scope of the Algerian Study

The main purpose of this study was initiate thinking on the role that nuclear energy could play in meeting the energy requirements of Algeria. With that in view, two successive analyses were performed:

The first consisted in evaluating the final energy requirements which will result in the medium and long-term (by 2015) from the implementation of the economic development policies contained in the Five-year Plan (up to 1984) and in the proposals for the next decade (up to 1990) being studied by the

Algerian Ministry of Planning. This first analysis was carried out by examining as closely as possible the structure and factors which give rise to energy demands from the various final consumers in each economic sector: industry, agriculture, transport, services and domestic users, in order to determine not only the amount of final energy required but also the form that this energy should take: steam, hot water, various heat applications, fuels, electricity, etc. Where one form of energy can be substituted for another, scenarios are constructed to examine the economic consequence of a particular choice. Since the ultimate goal of the study was to examine the role of nuclear energy in the electricity supply only three contrasting scenarios were used to reflect the varying degrees by which electricity migh penetrate the Algerian energy system. The three scenarios were selected in collaboration with various energy experts in Algeria and were considered sufficient to allow, as a first step, clarification of the role that electricity might play in Algeria's global energy structure. This study was conducted by means of the MAED model (version MAED-1).

The second study is concerned only with the results regarding future electricity requirements, which are used as input data in order to study the optimization of Algeria's future electricity generating system. Various methods of generation were considered in order to make a sequential determination of the most economic pattern of expansion for the power generating system. This study was carried out by means of the WASP model (version WASP-III).

The starting dates and sizes of the nuclear power plants which would be economically justified were derived from this analysis. It is clear from the aforesaid that only the economic aspect has been considered in this analysis of the possible future programme for the development of nuclear energy in Algeria. This study is therefore only the first stage in the decision-making process and would have to be followed by more specific studies and analyses.

It should be borned in mind that the purpose of the study was in no way to solve the energy problems of Algeria (i.e. to produce a national energy and electricity plan for the country) but to propose methods of analysis which may allow the energy authorities of the country to gain a better idea of the impact of some social and economic decisions in the energy domain. Thus, enhancing the decision making process on energy matters.

An additional objective of the study was to enhance the country's capabilities for conducting energy and electricity planning studies. This was fully accomplished since all computer programs used for the analyses were transferred to Algeria and implemented in its facilities, and the Algerian experts were adequately trained in the use of these methodologies.

3.2 Conduction of the Algerian Study

There was a division of responsibilities between the IAEA and the national teams in carrying out the various tasks involved in the study. The national team was responsible for gathering and analysis of the information to be used, analysis of results, and preparation of the draft report. The IAEA team was to provide assistance and guidance in the conduction of the study and execution of the various computer runs needed, training the Algerian counterparts in the use of the computer models, and the implementation of these models on the Algerian computer facilities.

Concerning the activity of gathering of input information, it should be mentioned that this is a crucial activity of an ENPP study, which in the case of Algeria was facilitated by the fact that sufficient statistical data on energy production and consumption were available. However, a great effort by the national team, working in co-operation with experts from the various Algerian organizations concerned, was necessary in order to ensure consistency of this information.

A similar co-operative effort between the national team and experts from various Algerian organizations was required for selecting the different scenarios of development for the study, so as to ensure that these scenarios adequately reflected all presently scheduled and foreseeable development plans for the various sectors considered, allowing for technological improvements in installed equipment and the introduction of new technologies.

The preparation of the scenarios of development was a very important phase of the study whose execution required:

- The definition of a consistent socio-economic framework, which in the case of a developing country, amounts to selecting a form of development, i.e. to defining options and priorities and predicting structural changes in the economy while ensuring overall consistency.

- An identification of the factors determining energy consumption, and particularly electricity consumption, calls for an in-depth analysis of past trends which can be made only on the basis of detailed and reliable statistical data which are not always available in developing countries. In view of the time limitations and information available, an iterative approach was adopted for the study alternating between MAED runs, additional analysis and gathering of data and meetings with various Algerian experts concerned.

Given the purpose of the study, the variables selected to differentiate one scenario from another corresponded to those parameters which have a direct or indirect influence on the demand for electrical energy. Therefore, the scenarios chosen were based on a more or less equivalent (or at least not too contrasting) levels of final energy demand and strongly contrasting electricity demand levels.

This means: a) taking as a common basis for all scenarios identical trends in socio-economic and energy factors which are not influenced by electricity such as: level of steel production, heating needs per housing, population mobility, and vehicle consumption; and b) assigning electricity a greater or lesser role in meeting the demand for final energy by varying the technological or technical factors, e.g. breakdown of steel production into direct reduction technique and conventional steel-making, electricity intensity per monetary unit of value added per sector, etc.

With this in mind, a valid pattern of socio-economic development of the country was defined in accordance with the National five-year and longer term development plans for the Algerian economy and the most recent sectoral studies. Three scenarios were selected for the development of the electricity sector and were ranked as Low, Medium and High according to their levels of electricity consumption. The scenarios were then discussed and refined at informal meetings with representatives of the national organizations concerned with the view to determine a single, consistent socio-ecomomic framework for the tree scenarios.

Features common to all three scenarios

- In demographic terms: A strong growth of population leading to approximately 35 million in 2000 and 54 million in 2015, and a continuing trend toward urbanization [See Figure 4].

- In economic terms: GDP growing over the study period but at slightly decreasing rates over the study period. [See Figure 5].

- In social terms: Major housing programmes aimed, in a first step, maintaining the present rate of occupancy and then improving it slightly; greater individual mobility with an improvement in public transport in order to limit the use of private cars; and a substantial improvement in domestic equipment (increase in the number of appliances per dwelling) without reaching the levels comparable to the currently enjoyed in industrialized countries.

- In energy terms: Energy conservation through improvement of equipment efficiency; identical values for variables determining demand for final energy, apart from those with a direct bearing on electricity demand; and recourse on small scale to solar energy for low temperature heat applications in households and services sectors.

Qualitative Description of the Three Scenarios

As already mentioned the scenarios selected are ranked as Low, Medium and High according to the level of electricity consumption. The variables related to electricity demand and integrating the scenario concern this demand either directly (e.g., technical or technological factors, electricity consumption per unit value added in a given economic sector, use of electricity in non-specific applications such as space heating in households or furnace/direct heat in manufacturing industry); or indirectly for reasons of consistency.

The principal differences in the variables integrating each scenario are:

- specific electricity consumption per unit value added of the various sectors,
- use of electricity in industrial heat applications, specially in steel-making,
- railway electrification,
- specific consumption level ($kW.h/m^2/a$) in services sector,
- specific consumption level (kW.h/dwelling/a) in the domestic sector,
- use of electricity for heat applications in domestic and services sectors,
- use of solar in manufacturing industries (which for reasons of consistency was higher when the market penetration of electricity was relatively low).

Optimization of the investments in the electricity sector

The optimal pattern of development for the electricity generating system was studied over the period 1986-2015 on the basis of the three scenarios of electricity consumption selected and carrying out a separate optimization analysis for each scenario.

MAED/WASP Study for Algeria
Past and future trends in the total and urban population and average annual growth rate (see notes 1 and 2)

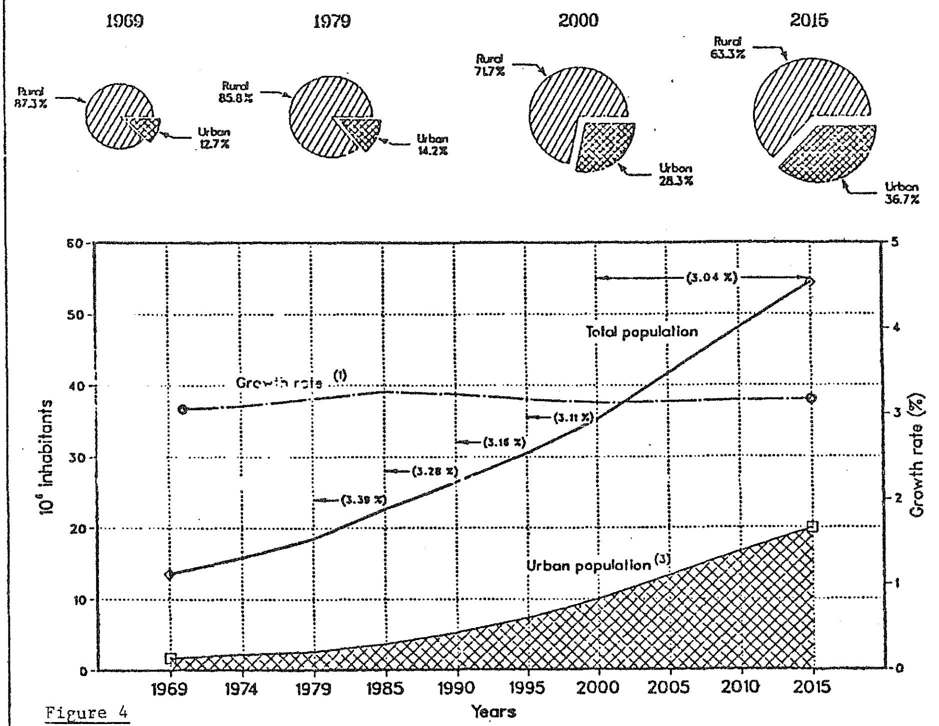


Figure 4

(1) Annual average growth rate of total population compared to 1969.
(2) Annual average growth rate of total population compared to 1979 (in brackets).
(3) Population in towns with more than 200000 inhabitants.

MAED/WASP Study for Algeria
Past and future trends in overall and per capita GDP and distribution by sector (DA 1979)

A : Agriculture
C : Construction
E. I. : Extractive Industries
M.I.: Manufacturing Industries
E : Energy
S : Services (inc. transport)

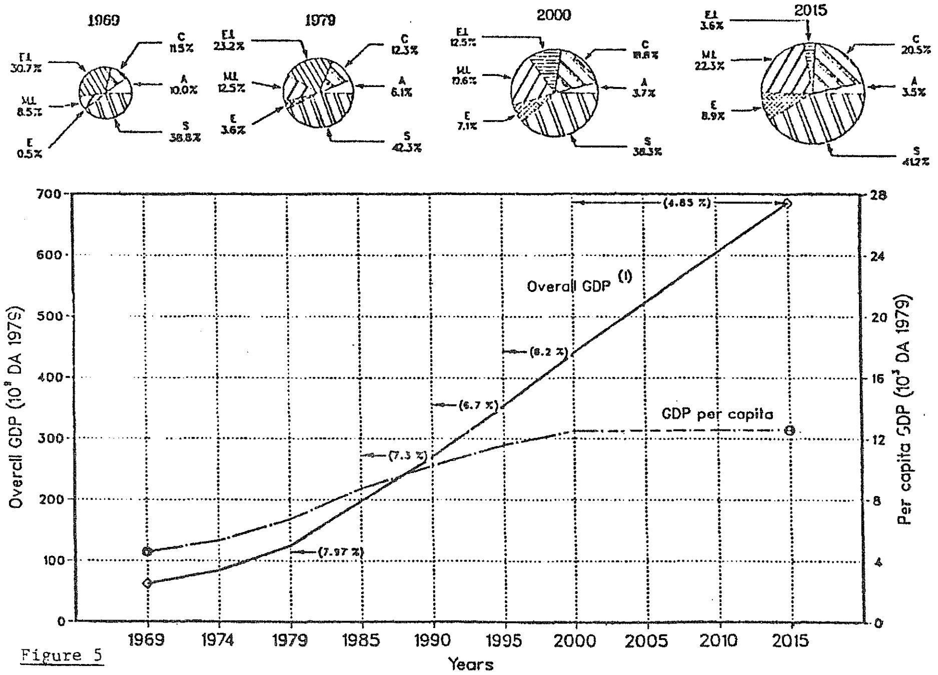


Figure 5

(1) Average annual growth rate of overall GDP compared to 1979 (in brackets).

MAED/WASP Study for Algeria
Breakdown of total demand for final energy
by energy form

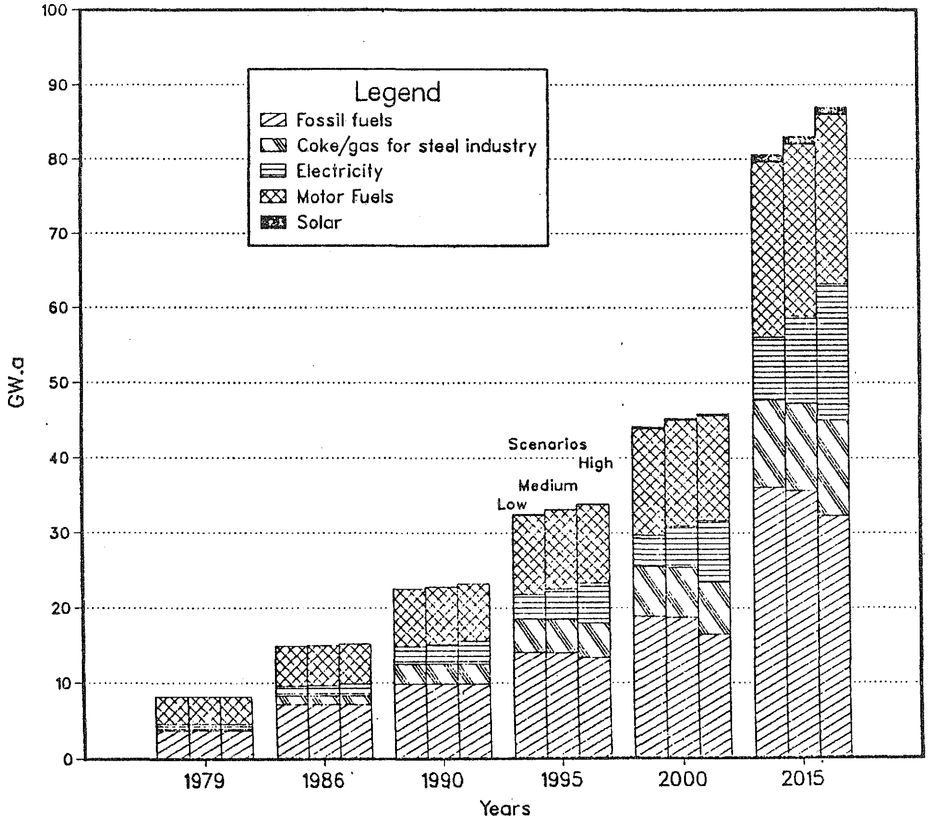


Figure 6

As for the analysis of energy demand, certain features were common to all three scenarios, in particular:

- the composition of the so-called fixed system including all existing and firmly committed additions and retirements of generating units,
- for expansion of the generation system only nuclear and gas-fired plants were considered as candidates and the sizes used were selected on the basis of system development and permitting effective competition between alternatives,
- the technical and economic characteristics of the power plants used were taken from the most recent information available with due consideration to future developments and local conditions,
- the fuel prices, set on the basis of international prices but reflecting also the market conditions for export of natural gas from Algeria, and
- the constraints to the expansion problem, which were set with due consideration to present practices in the country and expected development and also interconnections with neighbouring countries.

3.3 Summary of Results

3.4.1. Long-Range Energy Predictions

The main results of the three scenarios considered in the study are presented in Table I.

The demand for final energy is almost equivalent in all three scenarios ranging from 81 to 87 GW.a in 2015, (See Figure 6), and the participation of electricity in this total for each scenario is considerably higher than in 1979.

The breakdown of energy demand by economic sector shows a similar pattern of development for all three scenario (See Figure 7): for the first year of study (1979) the participation of each sector is about one third of the total, and at the horizon (2015) a predominancy of the industry sector is noticed since its share is almost 50% of the total consumption, in agreement with the industrial development objectives of Algeria and particularly for the steel, cement and petrochemical industries.

In comparing the results of the three scenarios, the methodology adopted at the outset of the study should not be forgotten: contrasting trends in electricity demand were to be viewed against a given pattern of development of the total demand for final energy as illustrated in Figure 8. The total electricity demand shown in this figure formed the basis for preparing the input data required for the analysis of the expansion of the electricity generating system.

3.3.2 Results concerning the development of electricity generating capacity and the role of nuclear power

The principal results are summarized in Table II and shown in Figures 9 through 11. In terms of capacity additions, up to year 2000, the expansion of the generation system may be covered by gas-fired units with a higher participation of steam thermal units. From that year up to 2015, the capacity mix is strongly influenced on the scenario hypothesis [see Figure 7]. Nuclear

Table I

ENERGY DEMAND FORECASTS ACCORDING TO THE VARIOUS SCENARIOS

1.1 LOW SCENARIO

Year	1979	1985	1990	1995	2000	2015
Final energy, GW.a	8.1	14.9	22.5	32.5	44.2	80.6
Growth rate*, %/a	-	10.6	9.7	9.0	8.4	6.6
Electricity, GW.a	0.6	1.3	2.3	3.0	4.1	8.4
Growth rate*, %/a	-	12.4	12.4	10.7	9.3	7.4
Electricity, % of total.	7.8	8.6	10.4	10.0	9.4	10.4

2.2 MEDIUM SCENARIO

Year	1979	1985	1990	1995	2000	2015
Final energy, GW.a	8.1	15.0	22.8	33.2	45.4	83.0
Growth rate*, %/a	-	10.8	9.7	9.2	8.5	6.7
Electricity, GW.a	0.6	1.4	2.6	4.0	5.5	11.5
Growth rate*, %/a	-	13.7	13.8	12.2	10.8	8.4
Electricity, % of total.	7.8	9.2	11.6	12.1	9.4	13.9

1.3 HIGH SCENARIO

Year	1979	1985	1990	1995	2000	2015
Final energy, GW.a	8.1	15.2	23.2	33.8	45.9	86.9
Growth rate*, %/a	-	11.0	10.0	9.3	8.6	6.8
Electricity, GW.a	0.6	1.6	3.1	5.3	8.2	18.1
Growth rate*, %/a	-	16.4	15.5	14.1	12.9	9.7
Electricity, % of total.	7.8	10.4	13.4	15.6	17.9	20.8

*All the growth rates are calculated from the base year 1979.

Table II

DEVELOPMENT OF ELECTRICITY GENERATING CAPACITY AND ROLE OF NUCLEAR POWER BY SCENARIO[1/]

Low Scenario	Medium Scenario	High Scenario
a. 16 575 MWe installed between 1986 and 2015	a. 23 250 MWe installed between 1986 and 2015	a. 38 025 MWe installed between 1986 and 2015
b. Units installed:[2/] 5 x 600 MW GS 27 x 300 MW GS 28 x 150 MW GT 17 x 75 MW GT	b. Units installed:[2/] 17 x 600 MW GS 23 x 300 MW GS 31 x 150 MW GT 24 x 75 MW GT	b. Units installed:[2/] 12 x 1200 MW PWR 14 x 600 MW GS 18 x 300 MW GS 49 x 150 MW GT 33 x 75 MW GT
c. Maximum annual capital investment in 2010 4 354 x 10^6 DA (1979) i.e. 0.7% GDP	c. Maximum annual capital investment in 2009 4 024 x 10^6 DA (1979) i.e. 0.8% GPD	c. Maximum annual capital investment in 2009 9 979 x 10^6 DA (1979) i.e. 1.7% GDP
d. Cumulative capital investment 61.5 x 10^9 DA (1979)	d. Cumulative capital investment 85.6 x 10^9 DA (1979)	d. Cumulative capital investment 188 x 10^9 DA (1979)
e. Annual requirements of natural gas in 2015 18.2 x 10^9 m^3	e. Annual requirements of natural gas in 2015 24.6 x 10^9 m^3	e. Annual requirements of natural gas in 2015 19.2 x 10^9 m^3
f. Cumulative requirements of natural gas 279 x 10^9 m^3	f. Cumulative requirements of natural gas 379 x 10^9 m^3	f. Cumulative requirements of natural gas 416 x 10^9 m^3

1/ Including only capacity additions made by the expansion programme (i.e. firmly committed additions are not considered).

2/ Types of units:

PWR: Pressurized light water reactor
GS : gas-fired steam unit
GT : gas-turbine

Figure 7

MAED/WASP Study for Algeria
Breakdown of total demand for final energy by economic sector

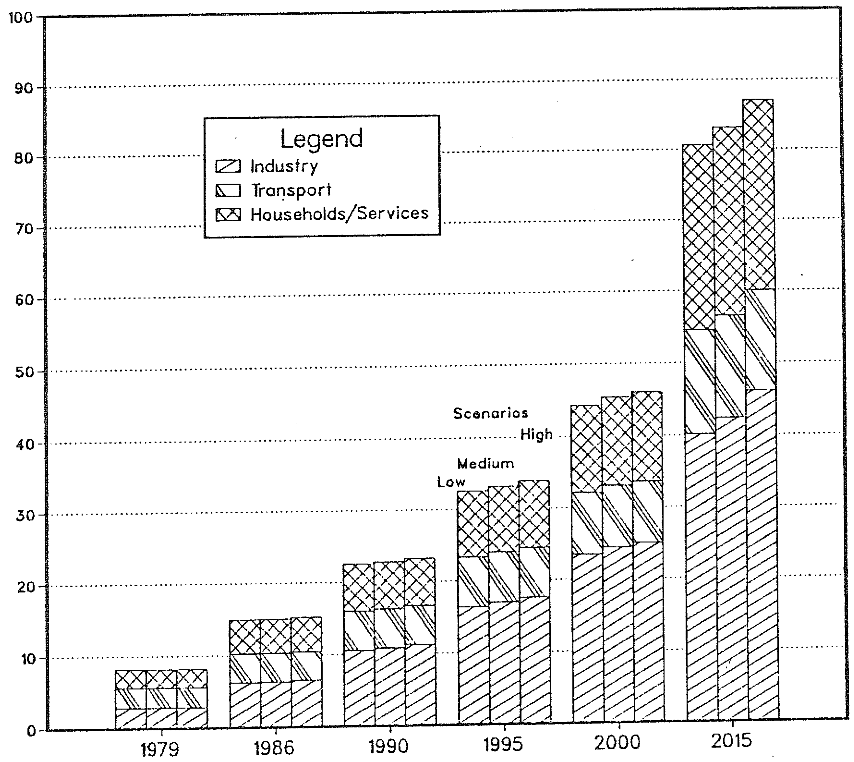
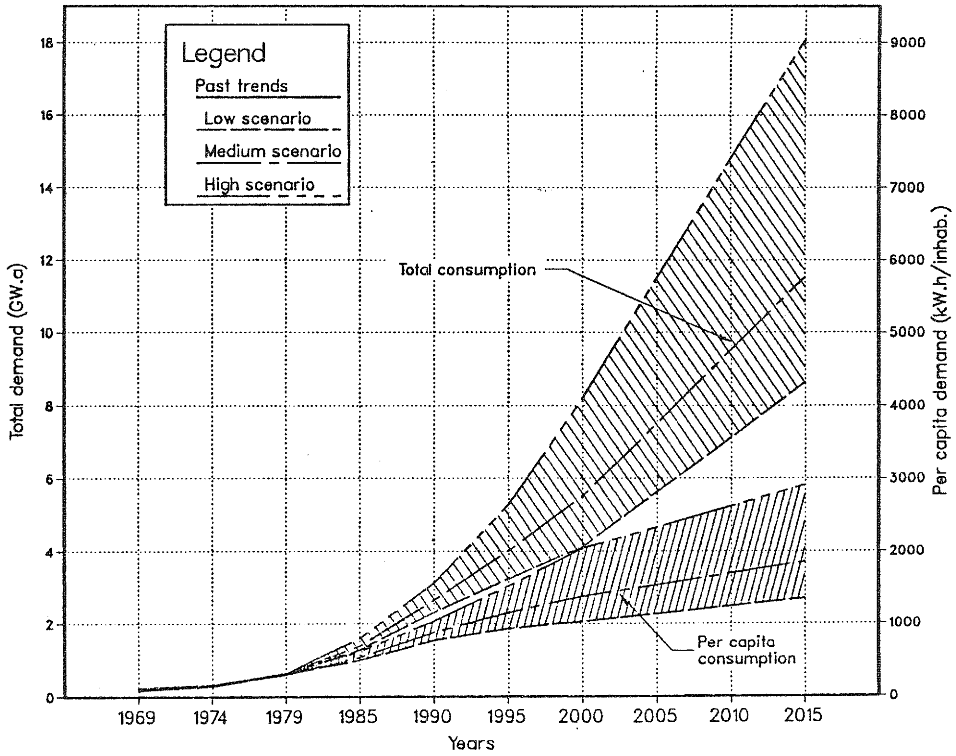


Figure 8

MAED/WASP Study for Algeria
Trends in total and per capita demand for electricity according to the various scenarios



power appears only in the optimum expansion programme for the High scenario since 2003. Two important aspects related to the optimum solution for each scenario were considered of prime interest due to their repercussions on Algeria's economy: the capital investments and the requirements for natural gas (a principal source of revenues for the country) imposed by these solutions, which are shown in Figures 10 and 9, respectively.

Sensitivity analyses were conducted using only the results provided for the Medium scenario to analyse the variations of the solution to changes in some basic parameters in order to provide the background for a decision to introduce nuclear power. Although conducted only for the medium scenario, the results can be easily extrapolated to the other two scenarios taking into account that there is time span of about plus or minus 6 years between each of them and the Medium scenario.

The sensitivity studies were executed in order to determine the impact on the reference solution of: -price of natural gas; the investment cost of conventional (gas-fired) units at various escalation rates; the cost of energy not supplied; the discount rates for investment and operating costs; and the modification of the reference solution tyring to define more realistic programmes of capacity expansion based on engineering practices and taking advantage of the economies of scale.

3.4 Conclusions of the study

In general, the study not only met its objective but also proved very instructive from the methodological point of view. The computer models used were all transferred to Algeria and assistance was provided for implementing these tools on country's facilities, and also the national team of experts was properly trained in the use of these models for energy and electricity planing.

Some effort to improve the analytical methodologies may arise from the experience gained with the Algerian experts trying to improve certain modelling techniques for a better representation of the Algerian energy system. Internally, the IAEA has also adopted a programme of work aimed at improving some weaknesses of the models identified during the study.

3.4.1. Energy Forecasts

In qualitative terms, the study is not confined to providing figures on electricity consumption but places these figures in a global energy context, identifying the factors which determine them. Despite all the difficulties encountered in assembling the data and some limitations of the present version of the MAED model, the advantages of the methodology and its overall consistency remained the decisive considerations (a new version of MAED, MAED-2 is underway).

In quantitative terms, the three scenarios largely covered the spectrum of possible trends in the electricity sector. It would be illusory to seek to give preference to one of the three suggested paths without referring to the national energy policy which would define the role of electricity in meeting the future energy needs of Algeria, a task beyond the scope of this study. It may, nevertheless, be stated that final energy demand and, more specifically, electricity demand will continue to show a marked increase over the next 20-30 years under the combined effects of a determined development policy, strong population growth and an increase in energy demand as a result of higher living standards.

Figure 9

MAED/WASP Study for Algeria
Development of installed capacity by type of power plant according to the various scenarios

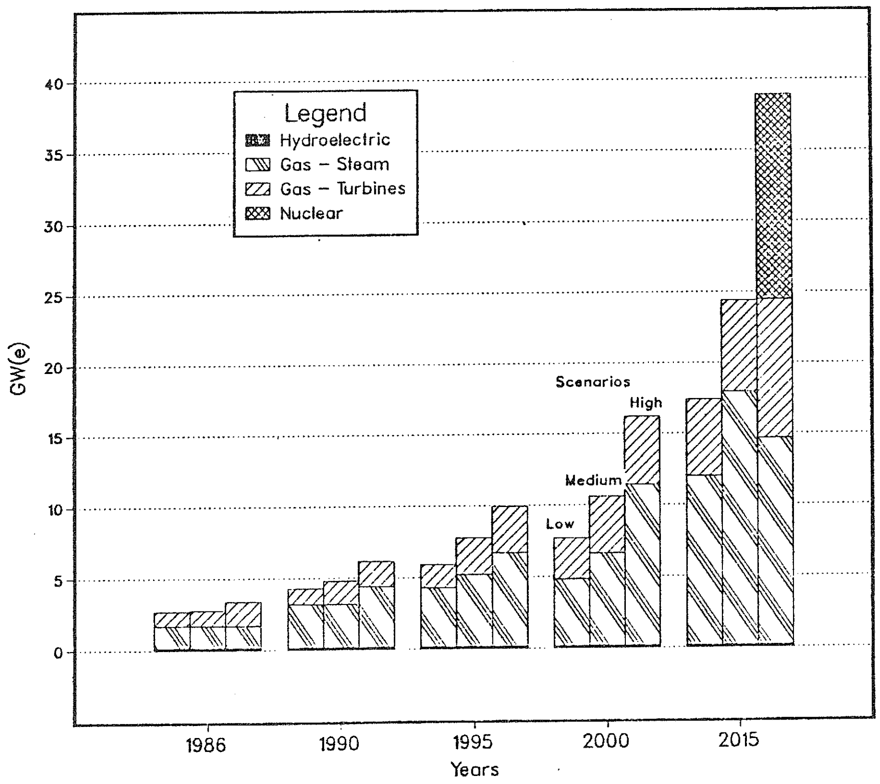


Figure 10

MAED/WASP Study for Algeria
Total cumulative investments in electricity generation according to the various scenarios

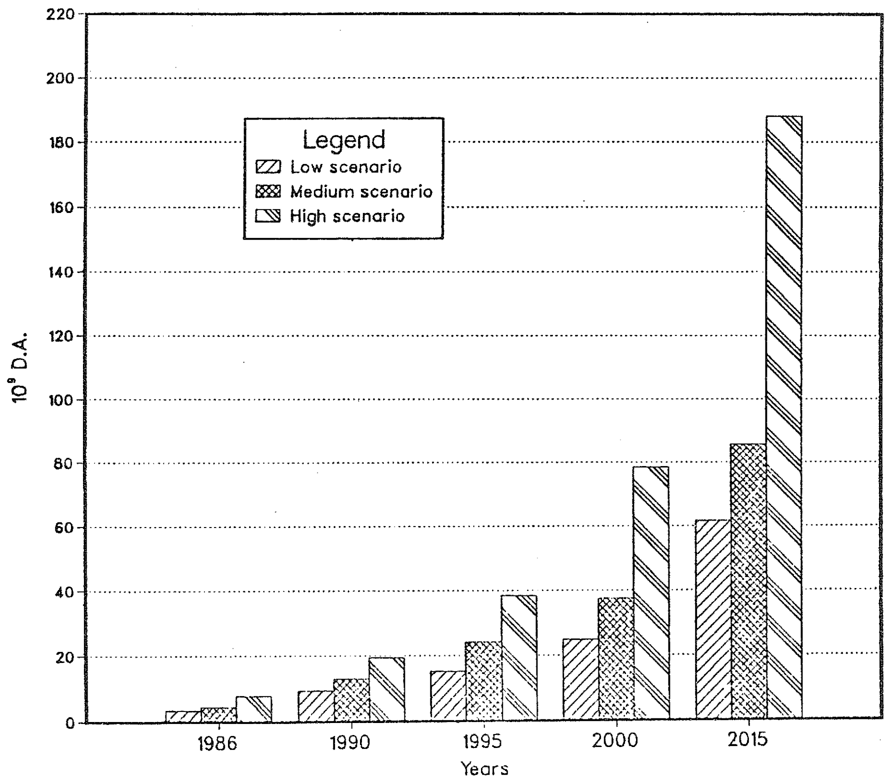
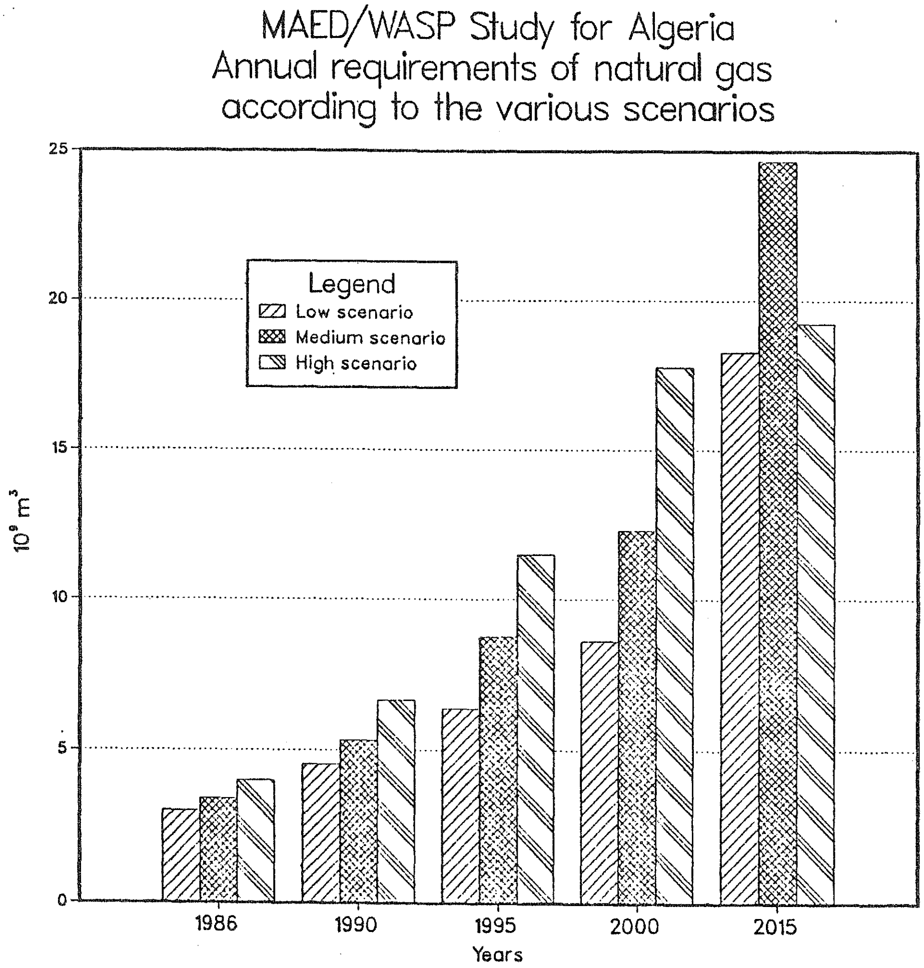


Figure 11


MAED/WASP Study for Algeria
Annual requirements of natural gas
according to the various scenarios
25
20
15
10
5
0
10^9 m^3
Legend
Low scenario
Medium scenario
High scenario
1986
1990
1995
2000
2015
Years

3.4.2 Expansion of the generating capacity and the opportunity of introducing nuclear power

The study was made using the WASP model; a methodology which has become traditional as a result of its widespread application and distribution by the IAEA. However, the procedure used still retains its originality because it refrains from providing final answers which would soon become obsolete owing to the changing technical and economic conditions. It seeks rather to identify in a dynamic way all the factors to be considered in the decision-making process.

Since the main objective of the study was to determine the role that nuclear power may play in meeting the demand for energy in Algeria, all alternatives studied were chosen with a view to help clarify the debate on this important subject and assist the decision-maing process. The results show that nuclear power could meet part of the overall demand for electricity from the beginning of the next century, if the appropriate decisions are made.

The key factors influencing these decisions are: the role of electricity in satisfying the energy needs of the country, the price of gas (at present the main fuel used for electricity generation), the availability of other forms of energy to generate electricity and the capacity of the country to cope with a high rate of investments.

If it is decided to install nuclear generating capacity in Algeria, it must be remembered that this is a complex technology whose introduction requires most careful preparations and close co-ordination between all the sectors concerned. Among the most important issues to be addressed are: setting-up of an institutional framework tailored to fit the specific requirements of this technology; training of personnel in order to guarantee that sufficient qualified staff is available to participate in all the phases of a nuclear power programme; availability of funds to support the programme; appropriate development of the national industry to secure its preparation in the construction of nuclear power plants; the search for suitable locations; the structure of the electric power network; etc.

3.4.3 Recommendations for follow-up studies

The results of the study were presented to the various Algerian authorities involved in the decision-amking process in the energy sector. Following this official presentation, it seems that a whole process of co-ordination and consultation will be implemented among the principal national organizations for adequate decisions on the development of nuclear energy.

Several further analyses and studies will be probably suggested and some technical assistance may be requested from the IAEA in the near future. In this respect, additional sensitivity studies should be carried in order to analyse the effect on the proposed solutions to major changes in the hypothesis chosen, specifically with respect to: the price of natural gas, the investment costs of nuclear and conventional plants and the adequate level of the national discount rate. These studies can be performed by the national team, which is now well acquainted with and in possession of all analytical tools.

Further, some other studies should be conducted in order to analyze the impact of introducing nuclear energy in the country, particularly on: the impact of a nuclear power programme on primary energy requirements; the impact of financing a nuclear power programme on macroeconomic development plans of the country; the balance of payment conditions; the selection of suitable types and sizes of nuclear reactors; the choice of and national participation in the nuclear fuel cycle; etc.

4.0 Final remarks on energy planning and role of the IAEA

The Agency has a demonstrated capability to assist its developing Member States in the economic aspects of planning their future electric power system within the overall framework of a coherent long-term energy plan. Through development of appropriate methodologies and approaches for energy and electricity planning and their use in planning studies for Member States, it has acquired a solid expertise in these fields. This has been recognized not only by the Member States themselves, but also by other international organizations with which the Agency maintains close co-operation activities in these fields, including in particular the World Bank (IBRD) in joint IAEA/IBRD electric power assessments missions to developing countries.

The Agency will continue to use this expertise in assisting developing Member States in the economic assessments of the role of nuclear energy within the national energy plan of the country. However, the development of an energy planning activity is a long-range undertaking requiring constant review, additions and improvement.

The evaluation of the economic benefits from nuclear energy in a developing country needs a broad-based and in-depth analysis of the total effects of a nuclear power programme on the overall economic development of the country. Three points must be emphasized:

- Nuclear energy development in a given country cannot be evaluated in an isolated way. Nuclear technology is only one among many means to supply secondary energy (such as electricity and heat), and nuclear power planning should be carried out within the context of all supply options. Nuclear power planning involves evaluation of the various types and forms of energy requirements, and it should consider energy and economic development planning of a country.

- Energy, electricity or nuclear planning is a problem which can be reasonably and rationally studied only by national energy specialists. The IAEA can provide advice and some methodologies but it cannot be a substitute for the national experts who must take the final responsibility for planning the development of energy supplies in their country. If needed, training to help develop local expertise can be obtained through the Agency training courses. The Agency strongly emphasizes than an ENPP study should be undertaken as a joint effort and carried out mainly by the national team, supplemented by assistance from Agency experts. Through this approach, a trained national team will be in a better position to understand the situation in its own country and be able to follow up on the studies initiated in co-operation with the Agency.

- Finally, it is emphasized that economic studies, such as those mentioned in this paper are only a first step in the long process of nuclear power planning. Many additional studies and analyses should follow, to determine whether nuclear power is a practical option and what the national implications of a decision to undertake a nuclear power programme would be. Complex problems such as impact on the balance of payment, financing constraints, manpower requirements, and local industry participation can be involved. These are additional factors that should be kept in mind when a country is evaluating the possibility to use nuclear energy to supply part of its electricity demand.

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LOAD MANAGEMENT AS AN APPROACH TO IMPROVING LOAD FACTOR AND REDUCING GENERATING CAPACITY REQUIREMENTS

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I. Introduction

The energy system consists of an integrated set of technical and economic activities which strongly interacts with the social and physical environment. Energy is a vital component in the economic and social well-being of a nation and must be considered explicitly in the formulation of regional, national and international energy supply policies. As the importance of energy in policy making has become apparent, energy system models are now used extensively for regional, national and international forecasting and for policy formulation and analysis.

During the past decade, important changes have taken place in this country's usage of electricity. Following the oil embargo of 1973-74, the rapid growth in the demand for power has been replaced by years of slower growth and expensive energy. The planning of capacity expansion in the electric utility industry has become more important and more difficult.

With continued inflation, the electric utilities' costs for new facilities have maintained the sharp rate of increase in recent years. These inflated costs, coupled with higher interest rates and longer construction periods which increase total capital requirements, have resulted in difficulty in securing sufficient funds for expansion programs. In some cases, utility bond ratings have been reduced because of insufficient revenues in the view of the financial community, and this has added further to the difficulty in raising capital.

The era of expensive energy and capital and rapid inflation has had a severe impact upon ratepayers due to the widespread increase in rates for electricity and other forms of energy. Because of the high cost of energy and the uncertainties associated with the expected growth of the demand for electricity, load forecasting and capacity planning are becoming critical issues for regulatory commissions. Unneeded capacity additions are generally viewed as a luxury which society can ill afford.

In the past, overbuilding capacity was not as serious a social problem as it is today. If a company overforecasted its peak demand and found itself in a situation of considerable excess capacity, rapid growth in demand would quickly alleviate the problem. Moreover, the declining real costs of fuel and the gains in productivity would tend to prevent the transformation of mistakes into higher rates. Today, mistakes in capacity planning cannot be easily dissipated, and therefore ratepayers will likely be saddled with uneconomical excess capacity.

Long-range planning can no longer be primarily aimed at service reliability. In the modern industrial environment it must also be used for demand forecasting, load analysis, generation expansion planning and financial planning. Long-range planning plays an important role in both the company's financial health and the future price of electricity.

The approach to planning and economic problems has changed in recent years. While a purely qualitative deduction based on intuition was formerly thought sufficient, an analytical and synthetic expression of the data is now resorted to. This approach is particularly useful in the case of economic problems of planning and operating a large electric power system which is characterized by a complex interdependence of many parameters.

Decision making involving complex and intricate systems can be aided by the use of mathematical simulation. Computers are essential tools when the problem's variables become numerous. The problem of determining optimum investment policies in the face of the increase in demand, high costs, the large number and diversity of alternate investment policies, and the numerical tedium of evaluating in-depth even a single policy has hastened the development of mathematical models to assist the system planners or the decision makers in scanning and costing alternative policies.

In determining the optimal generation expansion plan to provide a reliable service, a company should take into consideration various alternatives such as cooperation among utilities in improving interregional interconnections, energy conservation, diversification of energy sources, pricing policies, cogeneration and load management.

This study effort was aimed at shedding light on the attractiveness of a load management program and its impact upon the optimal capacity expansion plan of a company to meet its peak and energy demand forecasts over the next 25-year planning horizon.

The following sections will present the impact of load management upon the load factor, peak and energy forecasts, capacity expansion planning and financial planning of a utility company.

II. The Impact of Load Management upon Load Factor, Peak and Energy Demand Forecasts

Load management is a general term used to describe direct and indirect activities designed to reduce electric loads during certain periods and shift electric loads from one time period to another. Direct load management programs are used to prevent or limit the supply of electricity to particular customers and offer utilities opportunities to directly influence their load factors and load growth. These options include direct control of loads from a central location via radio or electronic signals.

The first step is to estimate the load control system costs and the diversified appliance load profiles with and without residential customer load controls. Load control system costs may include the investment in load control equipment, the costs of installation and maintenance of load control equipment, project management and system operation costs.

The expected diversified loads with and without load control of an average-sized residential appliance such as central air conditioning, electric water heating and electric space heating were determined on a typical weekday and peak day for each month. For water heaters, it included shutting off each appliance for three hours sometime during the day. For electric space heating, it involved cycling the appliance off during two three-hour periods. For central air conditioning, it involved cycling the appliance off for a few minutes out of every 30 minutes during a seven-hour period. The main objective is to control appliances whose demands can be deferred without noticeably inconveniencing the customer.

The monthly and annual load duration curves were projected based on historical hourly load data and forecasts of peak and energy demand. The historical hourly data were used to determine typical day load curves for each month for two day types: weekdays and weekend/holidays. Future hourly load curves were projected for each typical day for each future month on the basis of input peak and energy forecasts. Load curves were calculated for two scenarios. The first assumed that no load management would be implemented; the second scenario included the effects of residential load management on air conditioning, electric space heating and electric water heating.

As shown in Tables 1, 2 and 3, the results of load analysis demonstrated that with load management the peak load forecasts will be reduced by an average of 5.79%, the energy demand will be reduced by .27%, and the load factor will be improved substantially over the planning horizon.

III. The Impact of Load Management upon Capacity Expansion Planning

The capacity analysis was intended to determine the most desirable capacity expansion plan and the desirability of a load management program. A mixed integer/linear programming capacity expansion model and a probabilistic generation dispatching model were utilized to determine the appropriate size, timing and mix of the electric generating additions and retirements given a set of candidate unit costs and operating characteristics.

The objective function is to minimize the present value sum of operating costs and incremental capital costs. Four types of costs are considered:

- Fuel costs
- Variable operation and maintenance costs
- Fixed operation and maintenance costs
- Capital costs

Unit capital costs are transformed in the objective function to a levelized revenue requirement. All costs are in constant dollars, and the discount rate used to compute present values is the expected marginal cost of capital adjusted for inflation. The use of constant dollars and levelized capital costs helps to avoid problems introduced by selection of an arbitrary planning horizon.

The constraints are related to demand, reliability, unit operation and expansion possibilities. Unit operation constraints separately address forced outages and scheduled maintenance. Other constraints were included to describe the set of possibilities such as minimum and maximum load times and the maximum number that can be built of a particular type of power plant.

The dispatch and operation of the electric system was simulated to examine the costs of alternative expansion plans and to determine the fuel costs, cost of load probability, changes in unit availability, heat rates or loading order.

As shown in Table 4, the capacity expansion plan with load management has substantially reduced the construction requirements for additional generating units, and the present value of revenue requirements is reduced by $922 million over the 25-year horizon.

IV. The Impact of Load Management upon Financial Planning

The purpose of this financial analysis is to evaluate the impact of the two capacity expansion plans -- with and without load management -- upon the future electric price and the company's financial health. In addition, this study was performed to demonstrate that changes in the scheduled date for plant in service will affect not only capital expenditures and external financing but also depreciation, income taxes, required revenues and the price of electricity.

To measure the relative impact of the two capacity expansion plans on the financial health of the company, a financial analysis was performed using pro-forma financial statements that contain data specific to each of the two capacity expansion plans. For the customer impact analysis, the difference in revenue requirements and average electric price over the 25-year horizon were determined.

As shown in Figures 1 and 2, the proposed capacity expansion plan with load management will reduce the company's risk by improving its coverage ratios, reduce the quantity of funds the company must obtain from the capital market, improve its quality of earnings, reduce the revenue requirements from customers and reduce the average electric price.

V. Conclusions

The pressure of rapid inflation, tight capital markets, the energy crisis, environmental requirements, regulatory lag, and consumer resistance to the high cost of energy requires utility company management to be willing to and capable of reacting more quickly to events than in the past. This means that more sophisticated forecasting techniques and long-range planning are needed.

Load management and energy conservation should be seriously taken into consideration as a means of increasing energy production and consumption efficiency. The desired result of a load management program is increased reduction in the need for additional generating capacity, which would have a favorable effect on a utility's financial health and alleviate the pollution problem facing many states in the United States.

TABLE 1

Reduction in Peak Load Due to Load Management

Year	Peak Without Load Management (MW)	Peak With Load Management (MW)	Percent Reduction in Peak Due to Load Management
1982	5,274.7	5,274.7	0.000
1983	5,389.7	5,345.9	0.813
1984	5,565.9	5,473.1	1.667
1985	5,816.9	5,669.0	2.543
1986	6,152.0	6,032.4	1.944
1987	6,449.1	6,170.6	4.318
1988	6,629.0	6,274.2	5.352
1989	6,807.4	6,368.4	6.449
1990	6,934.7	6,602.7	4.788
1991	7,183.6	6,845.7	4.704
1992	7,400.6	7,027.8	5.037
1993	7,571.5	7,161.3	5.418
1994	7,730.5	7,311.7	5.418
1995	7,978.7	7,340.2	8.003
1996	8,194.1	7,655.8	6.569
1997	8,423.5	7,720.2	8.349
1998	8,599.6	7,944.8	7.614
1999	8,820.6	8,084.6	8.344
2000	8,972.3	8,226.9	8.308
2001	9,126.6	8,371.7	8.271
2002	9,283.6	8,519.1	8.235
2003	9,443.3	8,669.0	8.199
2004	9,605.7	8,821.6	8.163
2005	9,770.9	8,976.8	8.127
2006	9,939.0	9,134.8	8.091

TABLE 2

Impact of Load Management on Generation

Year	Generation without Load Management (GWH)	Generation with Load Management (GWH)	Percent Reduction in Generation
1982	33,762	33,762	0.00
1983	34,562	34,554	0.02
1984	35,419	35,401	0.05
1985	37,034	37,006	0.08
1986	38,390	38,349	0.11
1987	39,208	39,143	0.17
1988	40,120	40,046	0.18
1989	41,039	40,946	0.23
1990	41,977	41,867	0.26
1991	43,174	43,060	0.26
1992	44,241	44,119	0.28
1993	45,067	44,939	0.28
1994	46,014	45,883	0.29
1995	47,138	47,001	0.29
1996	48,376	48,236	0.29
1997	49,564	49,424	0.28
1998	50,598	50,446	0.30
1999	51,529	51,371	0.31
2000	52,154	52,048	0.20
2001	53,051	52,965	0.16
2002	54,725	54,639	0.17
2003	56,104	55,901	0.36
2004	57,501	57,181	0.56
2005	58,924	58,486	0.75
2006	60,372	59,809	0.94

TABLE 3

Impact of Load Management on Load Factor

Year	Load Factor without Load Management	Load Factor with Load Management
1982	73.1	73.1
1983	73.2	73.8
1984	72.7	73.8
1985	72.7	74.5
1986	71.2	72.6
1987	69.4	72.4
1988	69.1	72.9
1989	68.8	73.4
1990	69.1	72.4
1991	68.6	71.8
1992	68.3	71.7
1993	68.0	71.6
1994	68.0	71.6
1995	67.5	73.1
1996	67.4	71.9
1997	67.2	73.1
1998	67.2	72.5
1999	66.7	72.5
2000	66.2	72.5
2001	66.8	72.9
2002	67.3	73.4
2003	67.9	73.8
2004	68.4	74.2
2005	68.9	74.6
2006	69.4	75.1

TABLE 4

Capacity Expansion Plans

Year	Capacity Expansion Plan with Load Management (Additional Capacity - MW)	Capacity Expansion Plan without Load Management (Additional Capacity - MW)
1982		
1983		
1984		
1985		
1986	420 MW Pumped Storage	525 MW Pumped Storage
1987	420 MW Pumped Storage	525 MW Pumped Storage
1988		
1989		630 MW Coal
1990		630 MW Coal
1991	630 MW Coal	630 MW Coal
1992		
1993	143 MW Combustion Turbine	630 MW Coal
1994	630 MW Coal	630 MW Coal
1995		630 MW Coal
1996	500 MW Pumped Storage	500 MW Pumped Storage
1997	500 MW Pumped Storage	500 MW Pumped Storage
1998		630 MW Coal
1999	630 MW Coal	630 MW Coal
2000		630 MW Coal
2001		
2002	62 MW Combustion Turbine	
2003	630 MW Coal	
2004		
2005		
2006	630 MW Coal	
Total Revenue Requirements ($ Millions - Discounted)	11,834.448	12,755.555

FIGURE 1

Average Electric Price

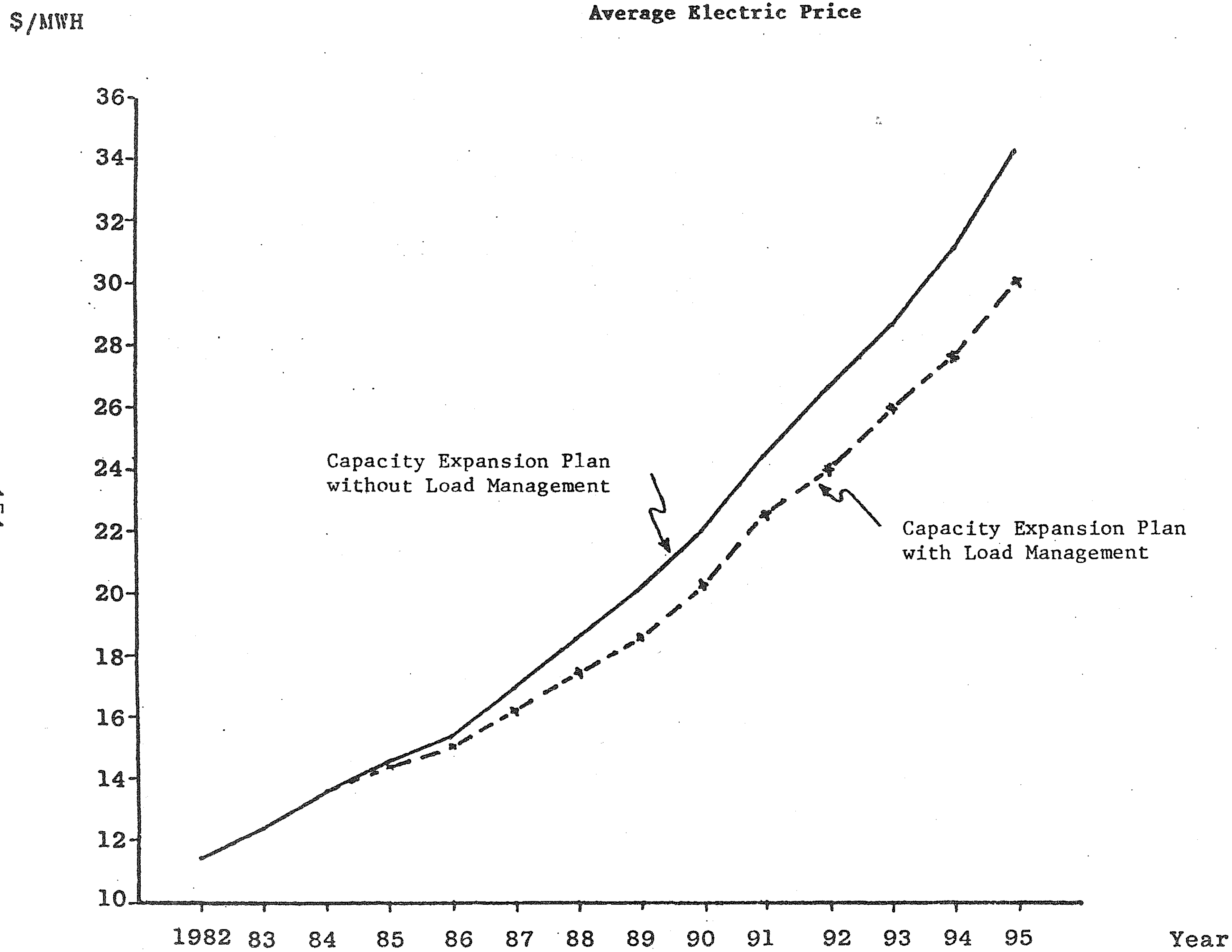
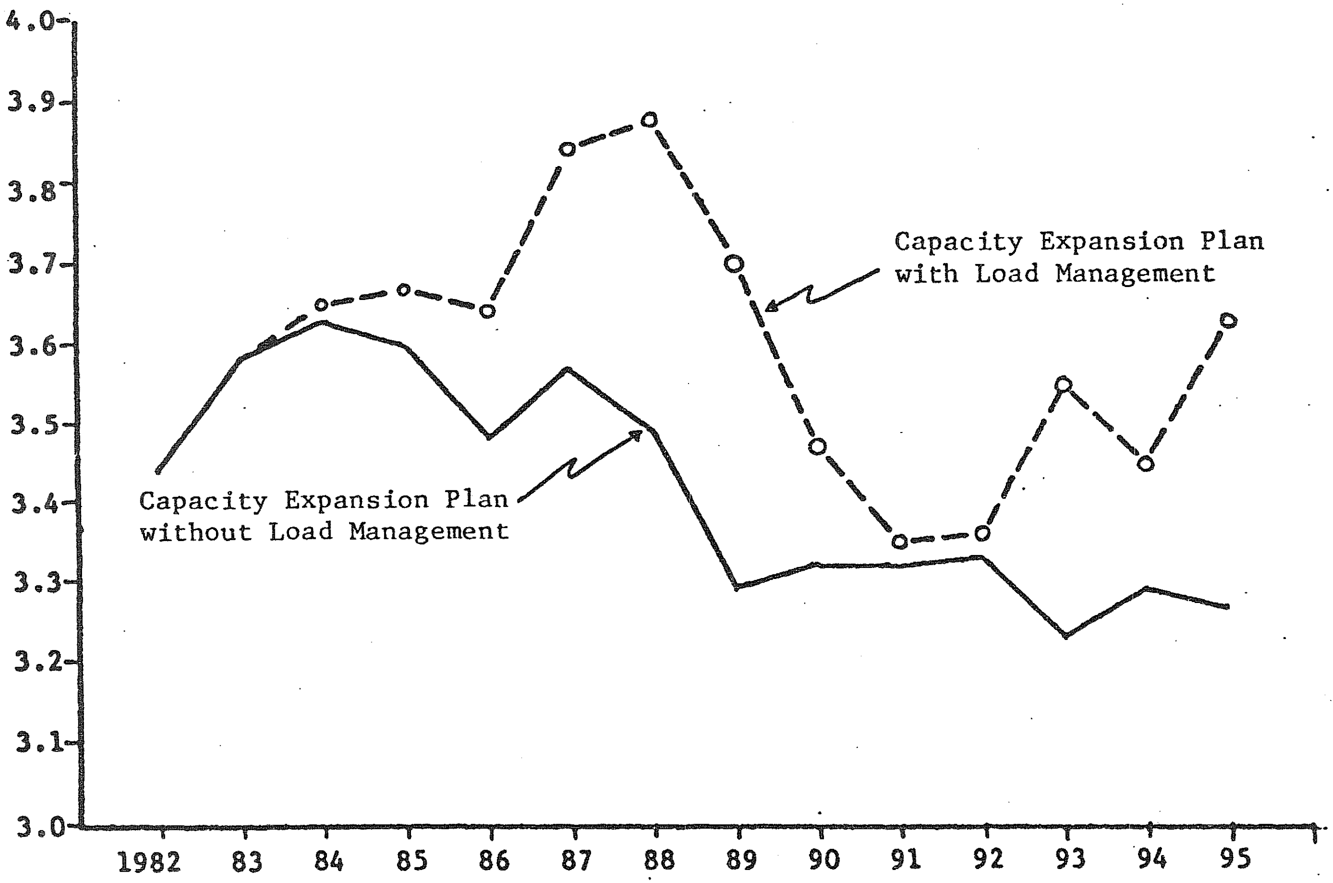


FIGURE 2

Interest Coverage Ratios
(Excluding AFUDC)



AN INDEPENDENT PEAK LOAD FORECAST FOR THE COMMONWEALTH EDISON SERVICE REGION USING A "HYBRID" ECONOMETRIC TECHNIQUE

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1.0 General Forecasting Methodologies

The two major methods commonly used to forecast peak electric loads are the "aggregate economic approach" and the "end-use approach". Briefly, an aggregate econometric approach uses the central hypothesis that economic relationships between very broad-based aggregate economic variables and power demand which have occurred in the past will continue into the future. Alternatively, the end-use approach seeks to relate power demand more specifically to the current stock of energy-using capital (since all electricity is used in one device or another) and then forecasts power demand by forecasting changes in the number and uses of devices over time.

Econometric forecasts center around an equation which hypothesizes that electric demand equals some function of a set of aggregate economic and demographic variables such as per capita income, the number of system customers, the number of electric appliances, etc. Because these variables have been found to be able to explain the level of peak electric demand, they must be projected over the range of the forecast. Since the forecaster is free to choose any explanatory variable he wants in the equation, he experiments with a wide assortment until he finds those variables which produce the best equation. "The best equation" in this case means that when many years of historic data for each of the explanatory variables and the peak load are examined, constant values (or numerical coefficients) can be found which make the equation correct. In other words, without knowing exactly why the explanatory variables add up to equal the power demand, the historic data indicates that over the years they do add up in the proper manner.

Each of these approaches share many aspects and data sources, and in practice no load forecast is ever purely econometric or end-use. For very sensible and practical reasons, most forecasts are a blend of primarily one of these methods augmented by aspects of the other. Moreover, the applicability of each of these methods can be severely constrained by the availability and quality of the data. It may be impossible to use one particular type of model, or it may require a concerted data collection effort over a number of years before a sufficient data base is established. Due to their relatively new status, good data is more commonly a concern with end-use models than with econometric ones. Yancey[1] has pointed out the dangers inherent in attempting to use a more disaggregated model than current data permits. Finally, econometric models can be expensive to produce due to their greater detail and data requirements.

All of these considerations have not changed this engineer's opinion that end-use models have a potentially greater command over forecasting, given the availability of good data. They have, however, prompted the creation of an intermediate "hybrid" methodology which strikes a balance between the economy and simplicity of aggregate econometric models and the sophistication and control of end-use models. This report reviews our efforts at analyzing and verifying the Commonwealth Edison Company's (CWE's) load forecasting models, ultimately leading to an independent forecast which applies the "hybrid" technique discussed.

2.0 The Commonwealth Edison Company

CWE is the nation's second largest private utility, with 2.96 million customers and 1981 energy sales of 66.202 Gwh. CWE possesses 16,658 MW of capacity in 18 locations and supplies most of the northeastern quarter of Illinois, including all of Chicago. The 1982 actual peak was 13,072 MW, 27.4% below the Company's present capacity.[2] CWE is one of the country's leading utility proponents of nuclear energy. In 1960, CWE started the first commercial nuclear reactor, (Dresden 1), which is now out of service for chemical decontamination. Since then, CWE has added 7 reactors to its system and generates about 40% of its power from nuclear fuel, one of the highest fractions of any utility. In addition, CWE has under construction 5 more nuclear units, all due to be completed by 1986.[3]

3.0 Commonwealth Edison's Forecasting Procedure

In its forecast,[4] CWE uses a primarily aggregate econometric approach modified by the ad hoc addition of some end-use considerations. CWE employs 2 aggregate econometric models to predict growth in peak load, Models IV and V. Both are in the form:

$$[\text{annual percentage growth in peak load}]_{(t)} = \sum^{i} A_i * \mathrm{Dln}_i$$

where

A_i = statistically derived coefficient, Dln_i = difference in the natural logarithms of the variables i between the years t and (t-1).

Model IV has 2 of these equations, one which predicts weather-sensitive load and one which predicts base load. This requires the utility to disaggregate each annual peak (i.e. the dependent variable) into these two components and then group explanatory variables into one equation or another.

At Commonwealth Edison, the next step after determining the prediction of the econometric model is the incorporation of end-use considerations in the forecasting process. This consists of arbitrarily selecting a group of topics which it feels are inadequately treated by the aggregate econometric models. It calls these issues "Other Factors Affecting Peak Load" or simply "policy issues". Edison's Statistical Research Section makes an ad hoc examination of these end-use policy issues which may affect its forecast results. Depending on the analysis, the form of the conclusion may be as concrete as a quantification in megawatts of the projected impact of the issue, or as vague as a statement such as "the magnitude of this impact is unknown". Furthermore, quoting from Edison's description of the forecast:

This work is highly subjective, the policy issues are often interrelated and it is believed that some initial effects can be explained by the models. Therefore, it would be inappropriate to accumulate the net possible effects of these policy issues to arrive at a total impact on system peak load.

The final step in Edison's forecasting process consists of the presentation of both forecast model results and "policy issues" results to a Committee of upper-level managers called the Load Estimating Committee or LEC. This Committee meets to adopt an official Company forecast. This is the point where Edison incorporates foreseeable changes in Company or government policies.

It is important to recognize that the LEC's decision is, without question, subjective. It is not good forecasting to simply adopt verbatim the results of an econometric computer forecast, especially given that one of the fundamental characteristics of the method is that it implicitly assumes that future demand relationships will resemble those of the past. As discussed above, this is one reason why additional end-use considerations are included in the LEC's determination. However, the inclusion of these considerations make the LEC's deliberation more judgmental and subjective rather than less.

4.0 Methodological Improvements

Our initial objective was simply to verify two key points concerning CWE's 1981-90 load forecast: First, was the form and structure of the econometric model unbiased and appropriate? Second, did the model utilize the most accurate and up-to-date information available? Had we determined that the answers to both these questions were, in our opinion, in the affirmative, no independent forecast would be required. We would have merely verified that CWE's forecast was the best aggregate econometric prediction available.

Although our consultants did express a number of reservations concerning the structure of Edison's econometric model, we did find CWE's Model IV to be a usable forecasting tool. In both Models IV and V, reviewers expressed reservations concerning the use and definition of the economic growth variables and the dummy variable theoretically included to represent the effects of the Arab Oil embargo. Although we prepared model runs using CWE's model V and our updated data series, we lent these results relatively little weight in the adoption of our official independent forecast.

As to data inputs, our treatment began by verifying historical and projected data employed in the Edison forecasts. A number of minor changes were made in the projection of explanatory variables based on the best and most recently available data. For example, we forecasted the future price of electricity to be lower than the Company's prediction due to tax law changes not yet incorporated into CWE's forecast. Many of CWE's data inputs were examined and accepted just as they were.

One of the explanatory variables in models IV and V is air conditioning saturation (ACS), or the percentage of Edison customers possessing air conditioners. The most significant change in our application of Edison's forecast method occurred in the development of the historic and projected data for ACS. Our attempt to refine the definition of this ACS variable led to the hybridization of CWE's purely econometric model.

The basic definition of ACS leaves open the question of whether one is measuring the fraction of families with any air conditioning, central air conditioning, or something in between. As the use of the data is the prediction of electric power demand, one requires an AC variable consistently related to the peak power required for air conditioning.

Edison's ACS variable was simply the sum of a fraction of those families with room air conditioning and those families with central air. This formula was used to produce an ACS estimate for all years despite the fact that purchasing and use patterns for air conditioners have changed greatly in recent years, as have average sizes and efficiencies of both room and central units. These are the kind of engineering or capital stock parameters which are easily changed in end-use models, but very difficult to embody in aggregate econometric equations.

Our analyses supplemented Edison's Census and Sales ACS data base with additional size, efficiency, and use data available from trade associations. From this we defined an energetically stable unit of air conditioning saturation called an equivalent central unit or ECU. Both historic and projected data were reformulated into ECU units before use in the econometric equations. The resulting ECU series was more consistent with national use trends. Interestingly, projections using our ECU data indicate that ACS as we have defined it will begin to decline in the Edison service region in the 1990's.

Table 1 contains a brief description of the treatment accorded the remainder of the econometric model variables in our independent forecast. Beyond the hybridization of ACS, most disagreements were minor (although not always insignificant). Several of the variables we thought to be underestimated in the sense that they would tend to imply too little peak load growth. We found predictions of natural gas prices so uncertain that we chose to produce two complete forecast sets incorporating alternative high and low gas price estimates.

5.0 Comparative Forecast Results

Table 2 displays the results of the statistical processing of the revised historic data series in our independent "Seniors"* forecast. To investigate the stability of the equations, we ran an additional set of regressions using one additional year's historic data (1967-81 as opposed to 1968-81). A comparison of CWE's results with our two forecast runs indicates that each of the results produced has some problems with significance and

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* "Seniors" refers to our client in the regulatory proceeding in which our forecast was filed.

counter-intuitive signs. Considering Model IV, which is the more sophisticated model, seven of CWE's fourteen variables have T-statistics under two, generally indicating less than desirable significance. In addition, CWE's gas price and electric price lagged one year have counter-intuitive signs.

Seniors' Model IV forecasts reveals an overall slightly greater degree of significance -- T-statistics are in many cases almost identical with slight improvements in the Weather-Sensitive constant, the electric price lagged variables, and customer index. Our 1968-81 results had the same counter-intuitive gas price sign as CWE's and nearly the same magnitude, but the 1967-81 runs have correct signs. This provides one of the best illustrations of the sensitivity of the forecast to the length of the historic data series.

As discussed above, our review of the structure and inputs to the load forecasting models closely paralleled Edison's. Our following steps regarding the "policy issues" also attempted to parallel Edison's as closely as possible. With the help of specialists in each particular area, we examined the same policy issues as did Edison. Starting with the workpapers from their forecast, our specialist was instructed to either verify their results or produce a more reliable alternative estimate. In cases where CWE's estimates covered a range so large as to render them almost useless, we asked the specialist to attempt to narrow the range. Each specialist proceeded with his or her analysis under the assumption of the "Business-As-Usual" conditions which were the basis for the econometric portion of the forecast.

Table 3 compares the findings of our consultants on these policy issues to CWE's official forecast. As was the case with the econometric variables, many of our findings agree closely or identically with Edison's. In several significant instances, we were able to narrow the range of impacts into one more useful for forecasting purposes. Our one significant disagreement on the policy issues concerns industrial fuelswitching. While CWE concluded that accelerating oil and gas prices would cause a fairly significant switch to industrial process use of electricity, our consultant felt that economics would continue to favor fossil fuels as sources of industrial process heat, especially if small, technologically advanced boilers continue to become cheaper and more available.

Finally, the results of both our re-estimated econometric model and our policy issues sections were presented to J. Stutz, who reviewed the complete forecast and workpapers and acted as somewhat of a surrogate LEC by making a judgmental recommendation for an official forecasted peak load growth.

Tables 3 and 4 compare each of the components of Edison's and our load forecast. The first row of Table 4 shows the average annual percentage growth rates predicted by the various model runs associated with each forecast. As stated earlier, Table 3 compares the results of the analyses of "other factors" affecting potential load growth. These two elements are combined with judgment, expertise and the results of other forecasts to produce the official forecast growth rate in row 2 of Table 4. This growth rate is combined with benchmark peak load (row 3) to produce the actual megawatt load forecast shown in Table 5.

In light of these components, it is interesting to contrast our results with those of Commonwealth Edison. Edison produced one result from each of its Model IV and V amounting to 1.9% and 2.4% respectively. When combined with the "other factors" and its judgment, Edison adopted an official growth rate of 2%.

In our forecast we produced five base case predictions from Models IV and V ranging from .64% to 1.61%, significantly lower than Edison's results. In addition, our "other factors" analyses indicated a most probable net negative impact on peak load over the coming decade. Our official growth rate is therefore slightly below the model predictions, or +0.5%. This is consistent with the track record of these models over the past few years as well as the observations by several of our consultants that these models as presently structured are likely to overpredict demand. The forecasts in Table 5 should also be viewed in light of Edison's recent record of approximately zero peak load and energy sales growth since about 1978.

While ours is only a 10 year forecast, barely long enough to plan and construct a major generating station, its implications in the long run are formidable. Under 2% annual peak growth, Commonwealth Edison will need by the year 2010, roughly 600 MW of new capacity put on line per year to maintain reliability. Under 0.5% growth in this same period, Edison would experience only about 80 MW per year of load growth.

6.0 A Hybrid Forecast Methodology

We are certainly not the first analysts to conclude that aggregate econometric forecasts of this type appear to be overly sensitive to data series length or that they have a tendency to overpredict during periods of structural economic change. These characteristics require the use of cumbersome ad-hoc analyses of extra-model impacts. On the other hand, end-use forecasts require massive amounts of data, much of which is not now collected by Illinois utilities.[5,6]

Faced with this dilemma, the idea of attempting to "hybridize" an econometric forecast may be the most prudent methodology to pursue from the standpoint of cost effectivensss as well as accuracy. In our forecast, we applied this idea only to the air conditioning saturation variable, apparently with some success.* It is conceivable that end-use considerations can be factored into most macro-econometric variables if the link between them and energy used is understood, and if sufficient data are available. For example, econometric growth is often used as an econometric variable. Though it is now often asserted that the overall economy is gradually getting less energy-intensive per dollar output, most GNP explanatory variables are not adjusted for this.

* As of this writing, results are available on Commonwealth Edison's 1983 metered peak. Without weather, vacation, or other adjustments, the 1983 peak to date is 14,517 MW.

If econometric forecasts are not producing accurate results, and if end use data are not fully developed for a service area, a hybrid forecast may represent a prudent and cost-effective forecasting method. We would certainly like to see further research on the subject and look forward to monitoring the accuracy of our forecast as the results of Edison's peak load are filed in the coming 10 years.

Acknowledgement

The Author gratefully acknowledges the assistance of W. J. Herrmann, A. K. Grandys, B. Kantor; the consultants participating in the forecast, especially J. Stutz; many reviewers and data sources, and Gwenda Landingham and Renee Wright, who prepared the transcript.

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Table 1. Treatment of CWE Load Forecasting Variables in Seniors Independent Load Forecast

Variable	Treatment
Customer Index	Edison data accepted
Illinois Gross State Product	Independent statistical analysis of state economic data
Real Price of Natural Gas	Independent analyses based on recent DOE reports
Real Average Price of Electricity Real Marginal Price of Electricity	Independent projection using financial simulation model
Number of Air Conditioners, A/C Saturation	Reformulation into ECU variable and recomputation of both historic and projected series
Weather Data	Edison data accepted
Real Per Capita Income	Edison data accepted

Table 3. Results of Independent Analysis of CWE Load Forecast "Policy Issues"

Policy Issue	Indep. Results: Impact on 1991 Peak Load (MW)	CWE Results: Impact on 1991 Peak Load (MW)
Cogeneration	-100 to -200 by 1987	-100 by 1985
Electric Vehicles	Same as CWE	"Little or no impact"
Appl. Effcy. Improv.	-313 to -388	"up to" -1200 MW
Fuelswitching	no impact	+900
Indust. A/C	+13 to +291	"up to" +570
Wind and Solar	Same as CWE	no impact
Petrol. Uncertainties	Same as CWE	"indeterminate decrease"
Demand Control Devices & Load Management	-165 to -296 by 1990	"up to" -270
Time-of-Day Rates	Minimal under current provisions	Not examined in most recent forecast

TABLE 2: Comparative results of CWE forecasting models IV & V

Model equation	Explanatory variable	Seniors Independent Forecast Coefficient	T-Statistic	1981 Official CWE Peak Load Forecast (1968 - 81 Data) Coefficient	T-Statistic
IV, baseload (1967-81 data)	Constant	0.9602	1.415	1.5431	2.342
	Customer Index	0.4801	0.986	0.1167	0.248
	Illinois gross State product	0.6919	5.825	0.7630	6.376
	Gas price index	0.0185	0.434	-0.0897	-1.729
	Electric price current	-0.1700	-2.371	-0.1428	-2.042
	price lagged one year	-0.0484	- .809	0.0280	0.499
	Conserve	1.3342	1.391	1.6075	1.744
	Electric price lagged two years	- .2428	-3.351	-0.1454	-2.341
	Electric price lagged three years	- .1404	-2.254	-0.1033	-1.698
	Electric price lagged four years	- .2517	-3.876	0.2395	-3.822
IV, weather sensitive load	Constant	-2.7488	- .830	- .6381	-0.234
	Temperture-humidity index	4.3103	9.973	4.2316	9.640
	Cumulative degree days	0.0690	1.672	0.0711	1.703
	Air conditioner saturation	0.803	2.955	0.6294	2.958
V (1968-81 data)	Constant	0.2110	.172	1.296783	1.6908
	Weighted electric price index	-0.1152	- .402	-0.358612	-1.7748
	Conserve	-3.2563	- .2958	-2.882476	-2.7091
	Per-capita income	-0.8541	4.657	0.930706	5.3819
	Weather index	0.5911	4.770	0.637977	5.9956
	Cumulative degree days	0.0204	3.367	.016243	2.5921
	Temperature no. A/C's	0.0321	2.572	.218761	2.9288

Computer Forecast Model Comparative Statistics System R^2

		System R^2
Seniors Model IV	1967-81	0.89509
Seniors Model V	1968-81	0.8947
CWE Model IV	1968-81	0.8353
CWE Model V	1968-81	0.8995

Table 4. Comparative Load Forecast Results

	Row (see text)	1982-91 Commonwealth Edison Official Forecast	Seniors* Independent Forecast	
FORECAST MODEL RESULTS (avg. annual percentage growth rates)	1			
Model IV Cases		1.9%	low gas price scenarios	0.64% 0.72%
			high gas price scenarios	0.69% 0.76%
Model V Cases		2.4%		1.51% 1.61%
Avg. annual compound growth rate, official peak load forecast	2	+2.0%	+0.5%	
Benchmark 1981 peak load (MW)	3	14,575	14,365	

* The two values for each model and scenario refer to two models for the projection of growth of air conditioning saturation over the forecast period. The upper figure uses a Gompertz curve model while the lower number uses a more generalized quadratic equation model.

Table 5. Seniors Independent Peak Load Forecast for the Commonwealth Edison Service Region 1982-91

Column	A	B	C	D
	Seniors Forecast		1981 CWE Forecast	
Year	Megawatts	% change	Megawatts	% change
1981(base year)	14,365	---	14,575	---
1982	14,437	0.5	14,650	0.5
1983	14,509	0.5	15,050	2.5
1984	14,582	0.5	15,450	2.5
1985	14,655	0.5	15,750	2.0
1986	14,728	0.5	16,050	2.0
1987	14,802	0.5	16,350	2.0
1988	14,876	0.5	16,700	2.0
1989	14,950	0.5	17,050	2.0
1990	15,025	0.5	17,400	2.0
1991	15,100	0.5	17,750	2.0

A NUMERICAL METHOD FOR DESCRIBING THE INVERTED LOAD DURATION CURVE AS A SUM OF TWO NORMAL PROBABILITY DISTRIBUTIONS

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Many techniques exist for the application of the Baleriaux methodology to electric utility system modeling. The original methodology calls for the convolution of the probability distributions describing the load facing the system and the generation outages. When the convolutions are done on a discrete basis, the computer time involved becomes costly. The method of cumulants has been applied for the purpose of performing convolutions in a speedy manner, however, the continuous curve describing the new distribution is difficult to use in a practical manner. This work addresses the problem of matching the inverted load duration curve, not to an asymptotic expansion, but to a sum of two normal distribution curves.

The procedure used to find a curve match utilizing a sum of two normals is based on the moment generating functions. The moment generating function for the discrete distribution is expanded to the first six terms. This expansion is done by determining the first six absolute moments of which the zero moment is equal to one. The coefficients of this expansion are compared term by term to the sum of two normal moment generating functions. The set of six nonlinear algebraic equations thus obtained is solved by the method of steepest descent. This method of solution is chosen because of its inherent stability and convenience. Since only the first few moments of the original distribution are used for solving the equations, the solution, matching two normals to the moments of the original distribution is not unique. This fact allows for additional flexibility. The binormal curve is then compared to several points on the discrete distribution. Adjustments are made to the binormal parameters and the method of steepest descent is again applied. This process continues until an acceptable curve match is obtained. The acceptance is based on tolerance levels which are programmed into the computer software. At this point a binormal description of a discrete distribution is obtained such that the binormal matches the shape of the discrete at the mean and tail and the first six moments of each distribution are equal, within a tolerance level.

The result of this work is a set of curves. The discrete inverted load duration curves are based on the IEEE Reliability Test System. These loads tend to have bimodality when considered on a full week or month basis. A full week or month is defined as 168 or 730 continuous hours respectively. The synthetic system of loads is matched by both the binormal set of curves and the Gram-Charlier asymptotic expansion. In the set of loads investigated, a Gram-Charlier expansion truncated to twelve terms was used. The Gram-Charlier expansion has been used extensively in power system modeling but this expansion has several faults, among them an inability to match bimodal distributions, and under many conditions, probabilities greater than one or less than zero can be encountered. The binormal curve match eliminates these problems.

A NUMERICAL METHOD FOR DESCRIBING THE INVERTED LOAD DURATION CURVE AS A SUM OF TWO NORMAL PROBABILITY DISTRIBUTIONS

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Introduction

The method of cumulants has gained many adherents in recent years. The primary advantage of the method is the speed in which convolutions and deconvolutions can be performed. Also, by describing thermal generation units in terms of their cumulants, the derating states for these units can be quickly accomodated. Unfortunately the Gram-Charlier asymptotic expansion which is used in the method of cumulants exhibits behavior which is not mathematically acceptable in all cases. Studies by Stremel and Dickson {1} indicated that the Gram-Charlier asymptotic expansion can be used effectively when the inverted load duration curve is described by Gaussian normal and the thermal generation units are described in terms of their usual cumulants. The benchmark program used for the purpose of comparison was TVA's FORGON program.

In as much as inverted load duration curves are generally bimodal and because of previous success in using the method of cumulants in production cost programs, the reasonable choice is to describe the inverted load duration curve in terms of a Gaussian normal and then make use of the usual method of cumulants. This paper presents a method which transforms hourly loads into a sum of two normal distributions.

Glossary of Symbols

$f(x)$: probability density function (pdf)

$M(j\omega)$: moment generating function $M(j\omega)$ is the moment generating function for the Gaussian normal.

$B(x)$: The binormal pdf.

α_i: The ith absolute moment of the given discrete distribution.

c_i: The ith real constant, $i = 1,2$

m_i: The ith mean, $i = 1,2$

s_i: The ith standard deviation, $i = 1,2$

Mathematical Development

The moment generating function for a probability density function, $f(x)$ given by

$$M(j\omega) = \int_{-\infty}^{\infty} e^{j\omega\chi} f(\chi)\,d\chi \qquad (1)$$

Expanding $e^{j\omega\chi}$ into its Maclaurin series and integrating term by term, the result is the well known expansion.

$$M(j\omega) = 1 + j\omega\alpha_1 + \ldots + \frac{(j\omega)^n \alpha_n}{n!} + \ldots \qquad (2)$$

Equation (2) is applicable to any distribution. The moment generating function for a Gaussian normal is

$$M_N(j\omega) = e^{(j\omega m - (\omega s)^2/2)} \qquad (3)$$

and can be found in mathematical statistics books, for example {2}, {3}.

Suppose a binormal pdf:

$$B(x) = \frac{c_1}{s_1\sqrt{2\pi}}\, e^{\frac{-(\chi - m_1)^2}{2s_1^2}} + \frac{c_2}{s_2\sqrt{2\pi}}\, e^{\frac{-(x - m_2)^2}{2s_2^2}} \qquad (4)$$

The moment generating function of $B(x)$ becomes

$$M_B(j\omega) = c_1 e^{(j\omega m_1 - (\omega s_1)^2/2)} + c_2 e^{(j\omega m_2 - (\omega s_2)^2/2)} \qquad (5)$$

Equation (5) is expanded in a Maclaurin series to yield

$$M_B(j\omega) = c_1(1 + (j\omega m_1 - (s_1\omega)^2/2) + (j\omega m_1 - (s_1\omega)^2/2)^2/2! + \ldots)$$

$$+ c_2(1 + (j\omega m_2 - (s_2\omega)^2/2) + (j\omega m_2 - (s_2\omega)^2/2)^2/2! + \ldots) \qquad (6)$$

Equation (6) is further reduced by combining like terms in $j\omega$ yielding

$$M(j\omega) = (c_1 + c_2) + j\omega(c_1 m_1 + c_2 m_2) +$$

$$\frac{(j\omega)^2}{2!}\left(c_1\left(m_1^2 + \frac{s_1^2}{2}\right) + c_2\left(m_2^2 + \frac{s_2^2}{2}\right)\right) +$$

$$\frac{(j\omega)^3}{3!}\left(c_1(m_1 s_1^2 + m_1^3) + c_2(m_2 s_2^2 + m_2^3)\right) +$$

$$\frac{(j\omega)^4}{4!}\left(c_1\left(\frac{s_1^4}{4} + \frac{3m_1^2 s_1^2}{2} + m_1^4\right) + c_2\left(\frac{s_2^4}{4} + \frac{3m_2^2 s_2^2}{2} + m_2^4\right)\right) +$$

$$\ldots \qquad (7)$$

The unknowns are c_1, c_2, m_1, m_2, s_1, and s_2. Equations for determining these six quantities are found by comparing equations (2) and (7), term by term. The comparison yields equation set (8).

$$c_1 + c_2 = 1$$

$$c_1 m_1 + c_2 m_2 = \alpha_2$$

$$c_1\left(\frac{s_1^2}{2} + m_1\right) + c_2\left(\frac{s_2^2}{2} + m_2^2\right) = \alpha_2$$

$$c_1(m_1 s_1^2 + m_1^3) + c_2(m_2 s_2^2 + m_2^3) = \alpha_3$$

$$c_1\left(\frac{s_1^4}{4} + \frac{3}{2} m_1^2 s_1^2 + m_1^4\right) + c_2\left(\frac{s_2^4}{4} + \frac{3}{2} m_2^2 s_2^2 + m_2^4\right) = \alpha_4$$

$$c_1\left(m_1^5 + 2\, m_1^3 s_1^2 + \frac{3}{4} m_1 s_1^4\right) + c_2\left(m_2^5 + 2\, m_2^3 s_2^2 + \frac{3}{4} m_2 s_2^4\right) = \alpha_5 \qquad (8)$$

Equation set (8) may be rewritten in the form

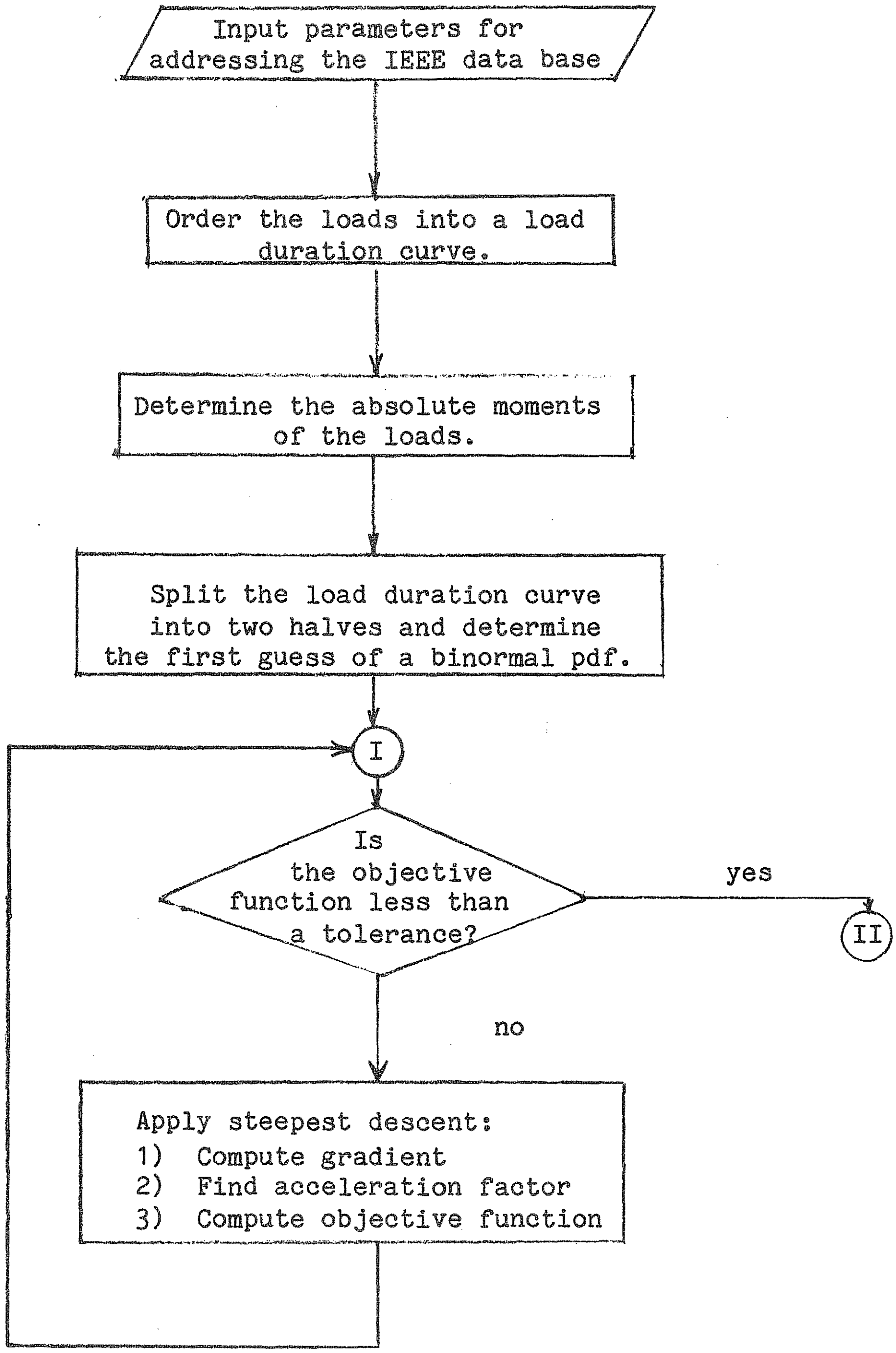
$$f_i(x_k) = 0. \qquad \begin{matrix} i = 1, 2, \ldots, 6 \\ k = 1, 2, \ldots, 6 \end{matrix} \qquad (9)$$

The method of steepest descent can be applied for the purpose of solving the set of six non-linear algebraic equations {4}.

At this point, nothing unique has been developed. The chief failing of halting the analysis at this point is simply that the solution obtained is not unique. This failing can be turned into an advantage. In as much as the method of steepest descent requires a starting guess to begin the solution, new starting guesses can be obtained by considering how closely the solution matches the given distribution. It has been heuristically determined that the best results are obtained when the means and the tails of the cumulative distribution functions are tested. If the means are not within a reasonable distance from each other then the constant, c_2, is adjusted. If the tails do not match, then s_2 is adjusted. The method of steepest descent is reapplied and a new solution is obtained. This continues until a match is obtained. The integrated binormal distribution thus obtained matches a given distribution in the first six moments, and in shape. The flow chart for the method is shown in Figure 1.

Application of the Method

The load data base as described in the IEEE Reliability Test System {5} was used to test this method. Figures 2 and 3 show the results from the method compared to a given set of system loads. Figure 2 represents week 14 of the IEEE Reliability Test System hourly loads and figure 3 represents a month of loads beginning at the start of week 14. The loads were normalized with the peak annual load being 1.0 per unit. The binormal solution for these figures are itemized in Table 1.


Input parameters for addressing the IEEE data base
Order the loads into a load duration curve.
Determine the absolute moments of the loads.
Split the load duration curve into two halves and determine the first guess of a binormal pdf.
I
Is the objective function less than a tolerance?
yes
II
no
Apply steepest descent:
1) Compute gradient
2) Find acceleration factor
3) Compute objective function

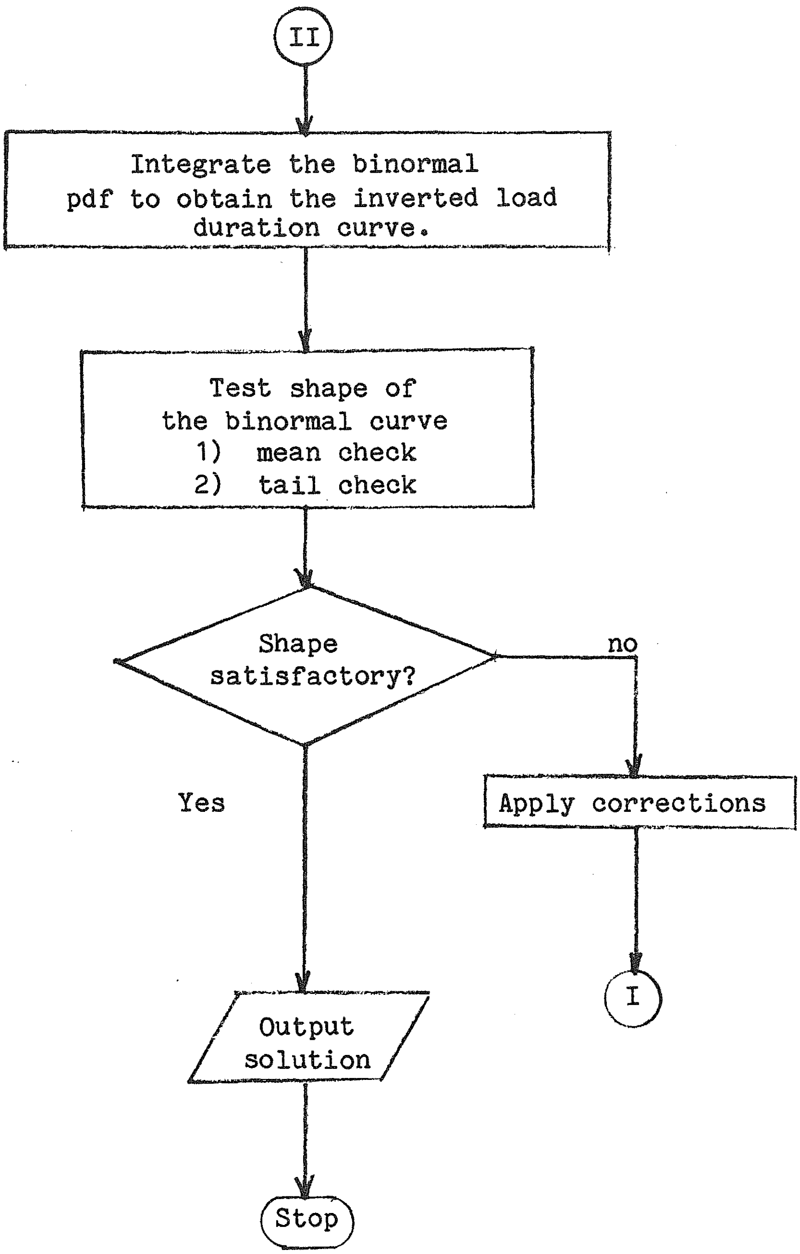


Figure 1

Conceptual Flow Chart of the Method

Table 1						
Figure Number	c_1	m_1	s_1	c_2	m_2	s_2
2	0.5133	0.4682	0.0434	0.4867	0.6688	0.0405
3	0.4595	0.4637	0.0449	0.5405	0.6742	0.0762

Conclusion

The method which has been described in this paper yields results which are appealing. The method is automated, thus no human is required in a program loop in order to check the shape of the curve used to describe an inverted load duration curve. The binormal curve is readily used with the method of cumulants in the development of system models. Since the cumulants of a distribution are related to the moments of said distribution, the binormal distribution found by the method described herein is within a small error of the moments of the distribution to be matched. It is hoped that this method adds another useful tool to the workbench of the system planner.

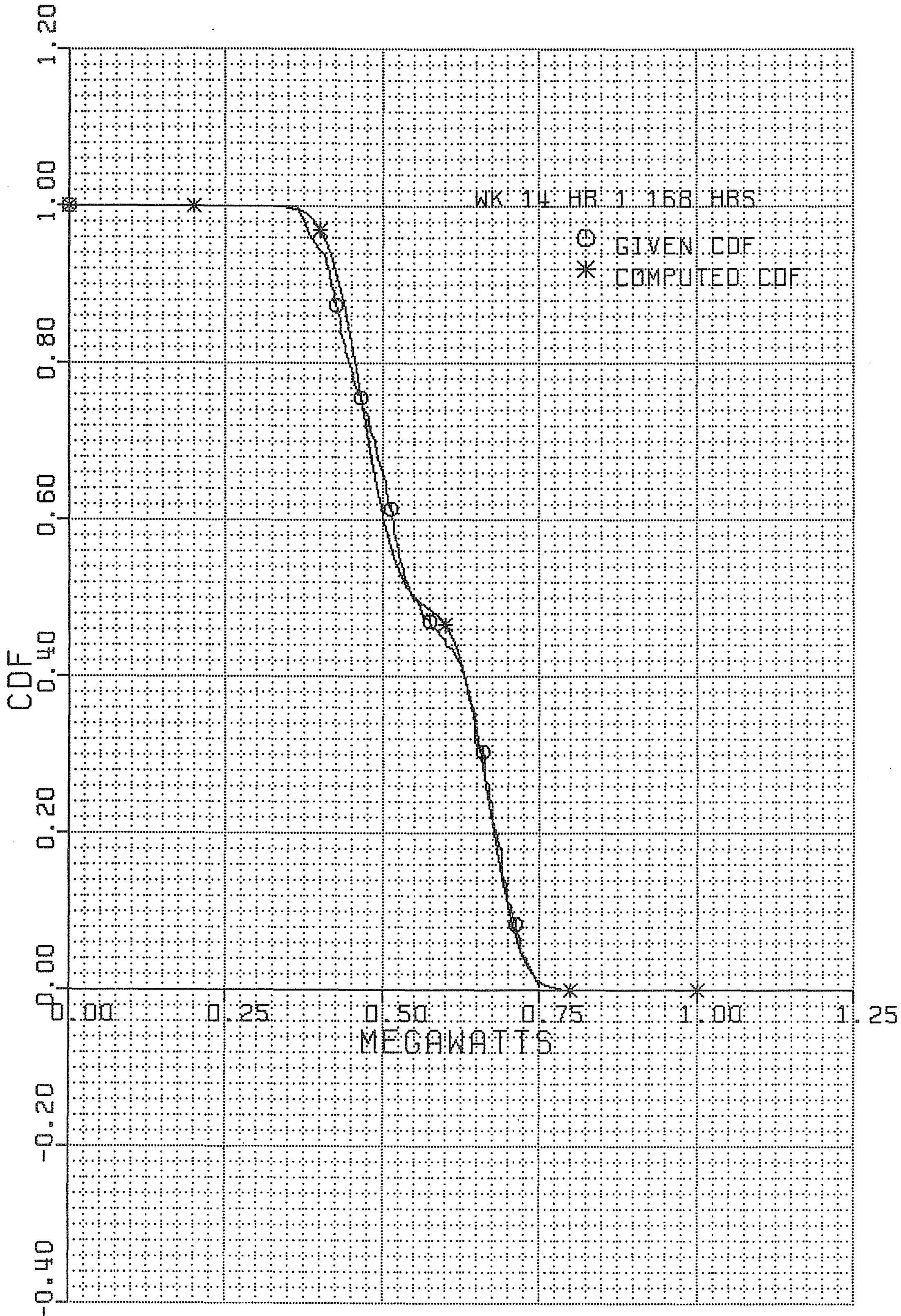

WK 14 HR 1 168 HRS
GIVEN CDF
COMPUTED CDF
CDF
MEGAWATTS
1.20
1.00
0.80
0.60
0.40
0.20
0.00
-0.20
-0.40
0.00
0.25
0.50
0.75
1.00
1.25

FIGURE 2

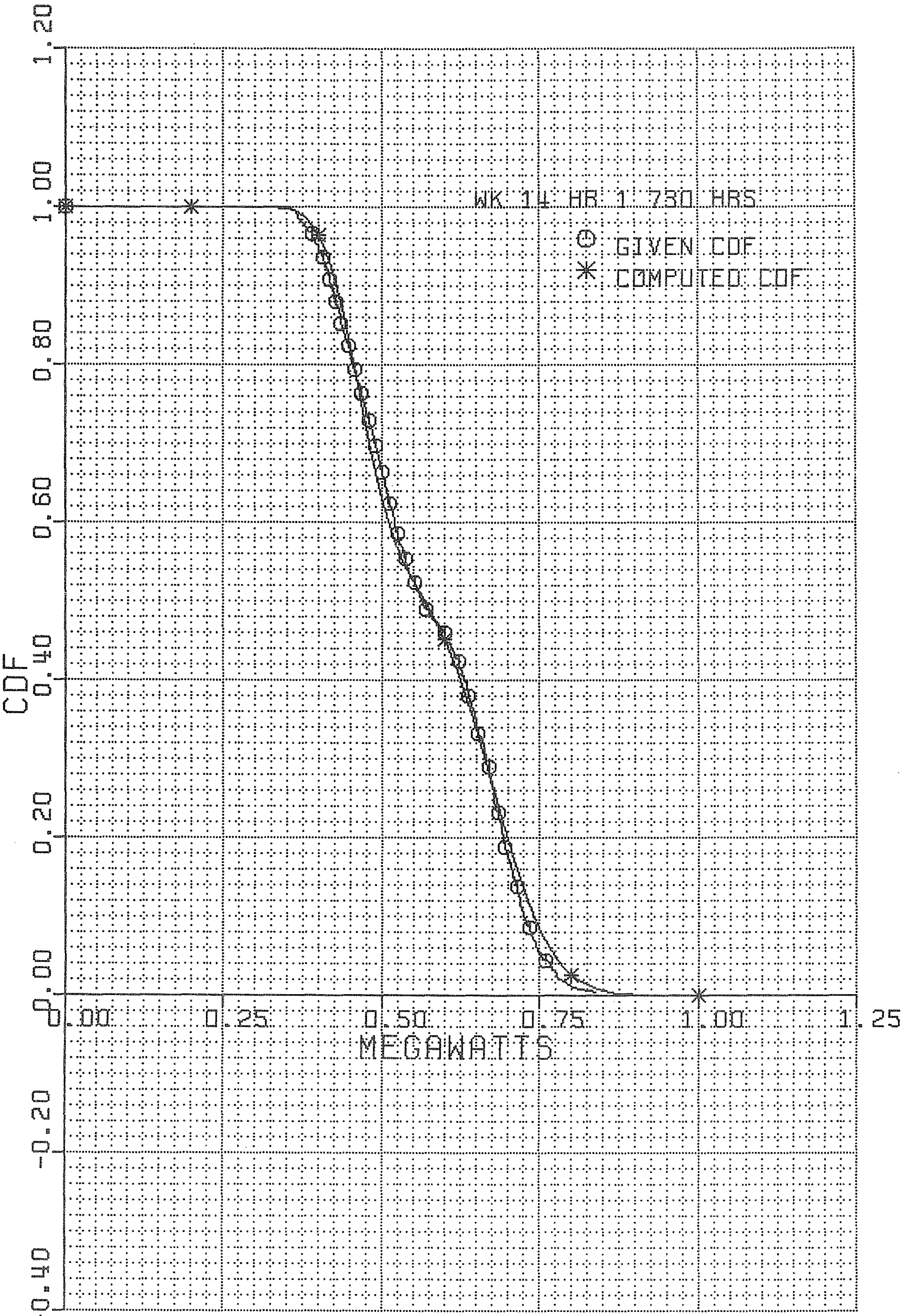

WK 14 HR 1 730 HRS
GIVEN CDF
COMPUTED CDF
CDF
MEGAWATTS
1.20
1.00
0.80
0.60
0.40
0.20
0.00
-0.20
-0.40
0.00
0.25
0.50
0.75
1.00
1.25

FIGURE 3

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LOAD FORECASTING AND CAPACITY EXPANSION, ON A MICRO

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1. Line of Research
1.1 Limitations of Mainframe Utility Models
1.1.1 Under-utilization

Approximately two years ago, it became clear to us that mainframe based utility models are seriously underutilized. Models with extremely sophisticated mathematical structure, purchased at great expense, were nevertheless excluded from the mainstream of utility planning and ratemaking. Even when they are used, there is often a misunderstanding or misinterpretation of what the models could accomplish. Among investor-owned electric utilities in particular, there are millions of dollars of such software literally lying around unused or underused.

1.1.2 Human-use Factors

Mainframe based utility models are underutilized for the following reasons: a) Mainframe models are cumbersome to use, and generally involve long turnaround time due to the interaction of users and the DP department; b) Data base maintenance on such models is quite difficult, sometimes intractable; c) Mainframe models are difficult to use, complex, and thus the results hard to interpret.

These human problems are what makes mainframe modeling of limited usefulness.

1.2 Development of Electric Strategy(TM)
1.2.1 Technical Objectives

Two central objectives guided our development program. The first objective was to make it much easier for the user to operate a serious utility model and maintain its data base. Such a model would be much more widely accessible. The second objective was to attain the technical/mathematical credibility of the conventional mainframe models, or at least to abstract as little as possible. Underlying this objective was the realization that precision in isolated technical areas could be swamped by the uncertainty in inflation, interest rates, fuel prices, load demand, etc. As long as a model has quick turnaround and is flexible enough to evaluate such uncertainty, the precision lost because of some missing technical detail may not really be that important.

1.2.2 Hardware Limitations

Putting sophisticated utility modeling tools on 48K eight bit micro-computers was certainly not an easy task. The limitations were most evident in memory size, affecting the maximum size of the data base and complexity of some calculations, and the speed of calculation including simple arithmetic. Even on this older technology micro, many of the limitations are overcome by creative use of RAM, diskette media, and a mathematical approach.

2. Load Forecasting, on a Micro

2.1 Technical Objectives

2.1.1 Usefulness as an Investigatory Tool

There is really nothing special about the mathematical structure of the Load Forecasting Model, or for that matter any of those in the Electric Strategy(TM) series. What is unique is how the user environment is structured, and the emphasis upon ease of use. The sophisticated user can just as easily access SAS, SPSS, or other conventional statistical systems, to accomplish a load forecasting analysis. In our load forecasting model, the user is guided, through the tasks which need be accomplished in a class or end-use function specific and system-wide load forecast. In this way, load forecasting is tailored for the utility modeler. The inexperienced or advanced modeler may quickly gain a good understanding of load trends under widely varying assumptions and scenarios.

2.1.2 Mathematical Credibility

The user selects and supports a set of potential explanatory variables for which conventional single equation regression based modeling is applied. All standard forecast statistics are printed for review. While load forecasting shies away from simultaneous equation forecasting, one still looks for evidence that such structural complexity adds to the precision of a forecasting exercise.

2.1.3 Flexibility

The set of explanatory variables, and the underlying data base, may be easily edited. This allows the user to explore a bit, and to observe the impact of uncertainty in the data set. This latter capability is important in load forecasting, where often the greatest problem is development of a good data set, and its validation.

2.2 Model Structure

2.2.1 Stepwise Multiple Linear Regression, Single Equation

A single equation multiple linear regression is developed for each customer class or end-use function. Up to six explanatory variables are accomodated in any regression, and a step-wise procedure is incorporated to search for the best fit, against various criteria. This best fit is then applied to the ten-year prospective period to generate monthly load forecasts.

2.2.2 Coincidence and Aggregation of Load by Customer Class or End-use Function

The character of demand in each customer class or end-use function is generally not coincident with respect to time with the other classes or end-use functions. Load forecasting incorporates a routine to accept coincidence factors and develop system-wide demand characteristics, fully aggregated. This is necessary if only for input into later Electric Strategy(TM) models, which are system-wide in nature.

2.2.3 Seasonality, Dummy Variables, and Other Features

Load forecasting is quite sophisticated in the area of seasonality, dummy variables, and other features of flexibility. The seasonality in particular allows the user to specify his/her peaking month and season, and the model then incorporates a characteristic trigonometric function.

2.3 Data Base Management

2.3.1 Underlying Philosophy

At a large, well-staffed investor-owned electric one day, a load forecasting manager told me that a micro-computer model was inapplicable since load data research was such a burdensome task. He asked "How can you do several runs, exploring as you say, when it takes a year to assemble a single data set?" My reply was that precisely because load research is such an exact science, there is a need to explore the impact of varying key elements of the data set. Load forecasting explicitly recognizes the problem of load research and incorporates quick editing features to allow the investigation of a wide range of applicable supporting data.

2.3.2 Ease-of-use

Our model is fully menu-driven, and the user is presented with a familiar environment for his/her investigation, complete with the peculiar aspects of utility modeling. Through these features, we very much hope to encourage a greater utilization of sophisticated forecasting tools, heretofore too often the purview of a couple of experts on staff or an outside consultant. In a sense, our models are a participative, democratizing product.

2.4 Role of the Results

The load forecasting model can be used in three ways. Its primary function has been to investigate and assess load trends quickly, under various scenarios. A second function is using formal load forecasting, particularly where an organization has not had the resources to do mainframe based forecasting, which is quite expensive. Thirdly, the results of load forecasting are used as input to other models of the Electric Strategy(TM) series, through the user's integrated data base, on a data diskette.

3. Capacity Expansion, on a Micro

3.1 Technical Objectives

3.1.1 Screening Function

Capacity expansion is basically a "what-if?" screening tool to narrow the range of feasible, least-cost generation construction schedules. Its quick turnaround and flexibility allows the user to pursue a very wide range of scenarios, and assess their impact on a system's future.

3.1.2 Role in Electric Strategy(TM)

Capacity Expansion is the fulcrum of the Electric Strategy(TM) series. This 6-model strategic planning system relies upon capacity expansion to generate the least cost construction schedule 30 years out. Capacity expansion accomplishes this in part by incorporating the results of the load forecasting model, or not as the user prefers. In the latter case, the user provides the load forecast as exogenous input.

3.2 Model Structure

3.2.1 Scenarios Evaluation

The Capacity Expansion model generates a series of scenarios as follows. First, each option is set to allow the minimum number of units to come on line during the earliest year in the option range. This is used as the initial scenario. Subsequent scenarios have this minimum number of units coming on line during later years in the range. The process continues for all possible combinations of multiple units during the option range, until all cases for the first option have been processed. At this point, the second option is set to process its next case (i.e. unit coming on line one year later), and the first option is reset to its initial condition. The process continues in this manner for all options, with the cases of the first option cycling most rapidly, until all scenarios have been processed.

This sequence was chosen because the earliest options will tend to have a more profound effect on the cost function, as a result of the present value calculations. After completion of the first cycle through the first option, you should have a good idea of the best way to configure the first option period, and you may even want to abort the run at this time and rerun, fixing this option. This approach can greatly reduce execution time by allowing your own professional experience to guide the option selection process, eliminating evaluation of unproductive scenarios.

3.2.2 Quadratic Load Curve and Demand Shortfall

Essentially, the user specifies a three-point daily load duration curve, the same shape for every day in a year of the prospective period. A piecewise quadratic function is fitted to the peak and "minimum" demand, and aggregate energy requirement. The curve shape may change from year to year, as escalation rates for energy, peak and minimum are also specified. Thereby, one may test for the effect on generation expansion of load management practices.

Each existing or potential generating unit has associated with it a probable forced full and partial outage rate. Applying a Monte Carlo sampling, units are then occasionally forced down for unforseen maintenance problems. Planned maintenance is also allowed. With "shortfall costs" specified in some detail in the model, the results thus turn somewhat on the probable costs of failing to meet load within the available system. Increments of shortfall capacity are specified to emulate the purchase of extra-system power, the cost of service limitations, and outright system failures.

3.3 Why Not Linear Programming?

Capacity Expansion does not apply linear programming to obtain an optimized solution. The 48K RAM environment simply could not support such a mathematical treatment in the detail we require. Our approach was to calculate the total costs of every alternative by brute force, and then order them. A user friendly approach is provided, which also limits in each run the set of feasible alternatives. Fair machine turnaround time is obtained.

3.4 Role of the Results

The output of Capacity Expansion is used in two ways. First and foremost, this screening model can support decisionmaking for capacity additions and load control techniques. It is quite complete, and prepared to provide useful information here. Second, Capacity Expansion supports other models in the Electric Strategy(TM) series. It does so by specifying the optimal capacity mix for the prospective 30 year period. System Generation and Revenue Requirements then simulate the operations and costs of operating this system.

4. Potential of Such Micro-models

4.1 Impact on Applications

Micro-computer based utility models will have a significant impact upon the planning and ratemaking process. This is true mostly because such models will greatly increase analysts' access to sophisticated tools, and should vastly increase utilization of them. We could expect that with much more powerful tools on the desktop of the analyst, more screening and strategy analysis will occur. In this volatile economic environment, such an evolution can only be helpful.

4.2 Current Line of Research

Much remains to be done. My organization's research and development program is focused on two areas. One goal is to obtain greater technical sophistication in the utility models. Our aim is to capture in a micro format all the complexity available only at the mainframe level today. The second goal is to improve the accessability of micro software. This will involve greater onscreen and printout graphics, more flexibility, and greater keyboard speed. I hope we can all enjoy these characteristics in utility models in the very near future. Thank you.

LOSS OF SPENT NUCLEAR FUEL STORAGE: THE EFFECT OF SYSTEM CAPACITY AND RELIABILITY

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Introduction

The storage of spent nuclear fuel is an issue currently under investigation by the Department of Energy. A bill passed in 1982 requires the President to select the site for the first of two permanent repositories for spent fuel by 1987. Until such a location is found, there are several temporary alternatives. These include pool storage, transshipment, reracking of existing pool storage, and emergency storage. DOE is also researching the possibility of consolidation of the spent fuel, and the use of dry casks for storage. These alternatives will only extend the use of nuclear power plants by a matter of years.

The Virginia Electric and Power Company relies heavily on the use of nuclear power to meet demands for electricity. Vepco's four nuclear units, Surry 1 and 2 and North Anna 1 and 2, presently account for approximately 40% of the utility's total generation. An analysis of Vepco's current plans for expansion indicate that this proportion will remain fairly constant over the next twenty years. Loss of spent fuel storage space necessitating shutdown of the nuclear plants would, therefore, have a severe effect on the utility's ability to meet demand.

This paper will analyze the effects of a loss of nuclear capacity on the Virginia Electric and Power Co. system due to a depletion of spent fuel storage space. The study period covers the years 1984 through 2001. The effects were analyzed in terms of system generation and reliability. Two computer models were utilized in this research. These models are part of an electric utility modeling system (COSIS) which was developed for the Virginia State Corporation Commission by Temple, Barker, and Sloane, Inc. and M. S. Gerber. The first model is a Capacity Analysis model (CAm). The optimal expansion plan, given a forecasted demand, for power was determined through this model. The second model is a Production Cost Simulation model (PCS). It determines monthly and annual generations, as well as fuel costs and unserved energy, for each of the utility's generating units.

Summary of Results

The loss of nuclear capacity would have a drastic effect on system reliability. This is most clearly indicated by the loss-of-load probability (the probability that system capacity cannot meet demand) and the reserve margin. The four nuclear units owned by Vepco provide a total capacity of 3305 MWs. If no action is taken, storage space at the Surry facility is expected to be depleted in the mid 1980's necessitating shutdown. The North Anna site could remain operational until the early 1990's even if no additional storage space becomes available.

Several alternatives for the storage of spent fuel were considered in this study. These ranged from a worst case of no temporary storage space to expansion of existing storage pools and transsshipment of fuel between sites. Given these different alternatives, nuclear capacity would be depleted at different points in time between the years 1984 and 2000. For comparative purposes, a base case which assumed no loss of nuclear capacity throughout the 1990's was run.

The first scenario will deal with the case of no alternative storage space and shutdown of the units occurring at loss of full core reserve. Scenario 2 is identical to Scenario 1 except shutdown occurs when all on-site storage space is filled. The third scenario models the expansion of the North Anna 3 storage facility. This scenario assumes shutdown at loss of full core reserve while Scenario 4 looks at the same situation with forced shutdown. The final scenario again assumes expansion of the North Anna pool, however, spent fuel from the Surry site is shipped to the North Anna site allowing Surry to remain operational until the 1990's. It would otherwise shutdown in 1984. Only shutdown dates at loss of full core reserve were available for this scenario, therefore, the case of forced shutdown was not analyzed.

The various scenarios were ranked according to the system reliability. Table 1 shows the results of each scenario in terms of reliability. Scenario 1, the worst case, assumes shutdown of the units to occur at loss of full core reserve. This is an assumption used by the Nuclear Regulatory Commission and results in a conservative shutdown date. The reliability of such a system is very low. Reserve margins drop below zero in several years and the loss-of-load probability reaches a high of 62.2% in one year.

Scenario 2, which assumes shutdown occurs when no storage space remains (forced shutdown), produces slightly better results in terms of reliability. Shutdown of the units is postponed a couple of years causing reserves and loss-of-load probability to be somewhat better in those years.

Scenario 3 assumes expansion of the North Anna facility. Reracking of the North Anna pool would increase the storage capacity by about 80%. Loss of full core reserve would be delayed eight years in this case. The reliability of this system does not become a problem, therefore, until the later years of the study. Reserves become negative in 1998 when all nuclear units cease operation. In only five of the study years did the system maintain an acceptable reserve margin of 20%. This is primarily due to the early shutdown of the Surry units in 1984. The loss-of-load probability averages 22% through 2001, increasing over time from 10% to 43%.

Still assuming the North Anna pool expansion, forced shutdown of North Anna would occur a couple of years following the loss of full core reserve. Scenario 4, as expected, is somewhat better in terms of reliability. A 25% reserve margin is maintained throughout the 1980's. However, due to the loss of Surry's capacity, the reserve falls to an average of 6-1/2% in the 1990's, falling to a low of -1-1/2% in the year 2000. The average LOLP was slightly less than 10% in the 80's, but rose to over 45% in 2001.

Scenario 5 analyzed the transshipment of Surry spent fuel to the North Anna facility. Reracking of the North Anna pool was again assumed. In this case, all nuclear units would cease production in 1991. Although transshipment would improve system reliability prior to 1991, the sudden loss of all nuclear capacity would have a severe effect in the 1990's.

The reserves of the transshipment scenario average over 31% in the 80's. But drop suddenly in 1992 from 29% to 3%, and then become negative throughout the rest of the study. The LOLP averages only 6.4% in the 80's, 44.5% in the 90's, and 25% over the entire period. This scenario is not quite as reliable in terms of LOLP as the scenario assuming pool expansion without transshipment, but average reserves tend to be slightly higher.

At this point in time, several other options for the storage of spent fuel may exist, however, this study does not attempt to model them.

Analysis

Nuclear capacity currently represents about 32% of the Vepco total capacity and accounts for almost 45% of total generation. Over the study period these averages will fall due to the fact that additional power requirements will be met by new coal capacity rather than nuclear. Two new nuclear units at the North Anna site were planned by Vepco for completion in the late 1980's. However, both units have since been cancelled. Even so, nuclear power should supply an average of 40% of generation over the next ten years and an average of 31% from 1993 to 2001.

The remainder of the system power requirements is met primarily through coal generation which should comprise 45% of total generation through 1992. Vepco's plans for expansion include only new coal capacity, however the size and timing of the new units has not yet been determined. In order to develop a feasible expansion plan, the Capacity Analysis model was run. The model was given the option of building any of three types of coal plants (550 MW, 840 MW or 1000 MW) to accommodate demand and maintain a 25% reserve margin. The resulting expansion plan consisted of eight coal plants, three having 840 MW capacity and five with a capacity of 1000 MW. One or two units were put on line in nearly every year between 1993 and 2001.

Given the addition of coal capacity, coal generation will continue to maintain a large portion of the total requirement, averaging well over 50% in the 1990's. Hydro units, combustion turbines, pumped storage and purchases contribute a combined amount of about 5% of total generation. Oil units generate between 5% and 15% of demand, averaging 8% over the study.

A pumped storage facility, currently under construction, is expected to be useful in reducing generation at times of peak demand. The base loaded units are to be more fully utilized to pump the facility at points of low demand. At peak demand, this generation will be used, displacing the relatively expensive peaking units. Should shutdown of the nuclear units be necessary, the base loaded energy available for pumping will fall and the pumped storage generation will subsequently fall.

Vepco's existing system and the expansion plan created by the Capacity Analysis model were input to the Production Cost Simulation model to create the base case or benchmark for all further runs. The resulting reserve margin indicates the total capacity of the Vepco/CAm system should be more than sufficient to meet demand. The PCS model, which requires monthly inputs, produced reserve margins significantly larger than the 25% reserve targeted by the CAm model. Reserves averaged over 35% through 1992 and 25% over the remainder of the study. A low of 16.6% occurred in 1993 while reserves reached 42.6% in 1986.

In terms of LOLP, the reliability of the system does not appear particularly worrisome. The LOLP, which measures the probability that system demand cannot be met, averages 7.3% over the entire period. This probability ranges from a low of 2% to a high of 15%. These are annual averages and may appear high due to months of peak demand. In these months spot purchases would probably be made to meet demand.

The number of days per month in which demand cannot be met can be determined through the LOLP to give a clearer picture of system reliability. This value averaged 1.4 days per month through 1992 and 2-1/4 days over the entire study period.

The load factor is a ratio of the average demand for energy to the peak demand. The industry standard is between 60 and 65%. Vepco maintains an average load factor of 72% ranging between 71 and 74%. This indicates the peak demand on the Vepco system is not as sharp as most utilities. Therefore, additional capacity needed to meet the peak does not greatly exceed capacity to meet average demand.

The capacity factor is a similar ratio, measuring the actual generation to total generation that could have been produced given 100% utilization of existing capacity. The base case run of PCS yielded an average capacity factor of 60%, ranging between 52 and 63%, and increasing slightly over time as demand outpaces capacity additions.

The first scenario to be discussed is a worst case scenario. No temporary storage space was assumed to be available except the existing on-site storage. This would result in a shutdown of the Surry units in October of 1984 and shutdown of North Anna in 1989. Shutdown was assumed to occur when the facility loses full core reserve.

As stated before, the reliability of this scenario is extremely low. While the base case system allowed an average reserve margin of 30.1%, a reserve of only 3.4% was maintained over the study period in the worst case scenario. The lack of power was most sorely felt in the 1990's when reserves averaged less than -5%. Reserves fell from a high of 30.7% in 1984 to a low in 1999 of -4.2%.

The loss of load probability also indicates the severe effects on reliability. Over the study period the average LOLP jumps over 350% from the base case average to 32.89%. Even throughout the 80's the LOLP averaged more than 20% while averaging less than 5% during the same period in the base case.

Expressing LOLP in terms of days/month of unmet demand, the system would be incapable of meeting demand an average of 10 days per month over the entire period and would not meet demand in 19 days a month during 1993.

Generation fell substantially given the loss of nuclear generation. Starting in 1990, total generation declined on average 20% from the base case. Less than 15% of the original generation from the pumped storage unit was obtained without the nuclear power. Generation from the other units rose in order to replace the nuclear power. In the case of some of the peakers, generation tripled in some years. Coal generation however was largely responsible for replacing the nuclear.

The capacity factor (capacity utilization measure) was somewhat higher in the scenario run, increasing to 66.3% from the base case value of 60% due to the increased generation of the individual units. Analyzing capacity factors of the different units, the base-loaded units already near full utilization, do not increase much, if at all. Utilization is calculated as capacity factor divided by equivalent availability. Cycling units in the scenario have higher capcity factors than the base case units but are not utilized fully. Peakers are utilized to a much larger extent, averaging over 80% utilization. This is significantly higher than the peaker utilization factor of 35% found in the base case.

Unserved energy at least doubled over base case values in every year, averaging an increase of about 450%. The average system cost was consequently larger, about 40% greater each year. Fuel costs rose due to low utilization of cheap nuclear power. These fuel expenses were an average of 20% higher than base case costs.

Scenario 2, similar to the first, was run assuming shutdown to occur when all onsite storage space is filled. This results in a forced shutdown of Surry 1 and 2 in 1987 and 1988 and North Anna 1 and 2 in 1990 and 1991, a few years following loss of full core reserve. The only differences between this run and the previous scenario are in the years 1984-87 and 1990. These are the years in which nuclear generation is still assumed to be available after full core reserve is lost.

Reliability in the 1980's is markedly better than the last scenario. The average reserve margin jumps from 12.28% to 19.67%, a 60% improvement. The loss-of-load probability averages 16.09%, falling from the worst case scenario average of 21.29%.

Scenario 3 modeled the case of reracking the North Anna pool. The pool, utilized most efficiently, would have greater capacity for storage of spent fuel. In this case, shutdown of North Anna due to loss of full core reserve would be delayed until 1997. The Surry units are still assumed to cease operation in 1984, again at the loss of full core reserve. This has the effect of limiting nuclear generation to about 55% of its original level prior to shutdown of North Anna, when all nuclear capacity is out of service.

Coal units were primarily responsible for replacement of nuclear generation, increasing as much as 18% over the base case generations. The relative levels of the less heavily used oil and peaking units were significantly greater although these units did not contribute quite as much to the total replacement generation. Total generation on a whole gradually declined, falling from approximately 3% in the early portion of the study, and over 18% in the late 1990's.

The use of pumped storage also dropped significantly. It produced about 60% its original generation in the 1980's and early 90's and to less than 1/3 during the late 1990's.

The reserve margin also fell to unsatisfactorily low levels, especially in the later part of the study. An average of 19% of capacity was available for reserves through 1992. However, only an average 4% reserve margin existed from 1993 through 2001, reaching a low of -4.2% in 1999.

In terms of loss-of-load probability, the situation does not look much better. The LOLP averages 22.1% throughout the study, with a low of 8.17% in 1987 to a high value of 43.2% in 2001. This equates to a span of power outages averaging between 2-1/2 and 13-1/6 days per month.

The fuel cost increased to an extent even though less power was generated. This was due to the costlier generation required to replace the relatively cheap nuclear power. The largest increase in fuel expense occurred in the mid-80's prior to the addition of coal capacity. Oil and gas units were utilized to a much greater extent causing a 25-30% increase in cost. This fell to between 10 and 15% for the remainder of the study.

The average cost of the system (in $/MWH) rose even more than the fuel cost, averaging an increase of 33% in the mid 80's, 23% in the mid 90's, and jumping back up to almost 40% in the later years of the study.

Unserved energy also increased as one might expect. The MWH's unserved rose to over 500% the base case level in several years, always at least double the original level.

The capacity factor averaged 65.0% over the entire eighteen year period increasing slightly over time. This average is a full 5 percentage points over the base case level, but slightly less than the worst case value of 66.3%. Utilization of the individual units increased significantly over base case levels, however, not to the extent the worst case scenario units increased. Again only the peaking units and the more costly cycling units were able to increase output to a large extent. The capacity factor of Yorktown 3, a #6 oil unit, increased an average of 52% over the base case while the worst case scenario required a 61% rise in the average capacity factor of the Yorktown unit to accommodate the additional need for power.

Scenario 4 again analyzes the case of reracking North Anna, however, shutdown of the North Anna units is not assumed to occur until 1999 and 2000 when all on-site storage is filled necessitating shutdown. Surry will cease operation in 1987 and 1988 when forced shutdown occurs.

This scenario produces similar results to the last, however, the consequences are not as extreme. The reserve margin tended to be somewhat higher, averaging 15.76% over the entire study. A 25% average reserve was maintained in the first 9 year period but dipped to 6.47% over the second 9 years. The low occurred in the year 2000 when capacity requirements exceeded capacity and a -1.5% reserve resulted.

The loss-of-load probability again emphasizes the adverse effect of nuclear shutdown. The LOLP, which averaged 18.8% over the study, grew to 43.15% by 2001. An average LOLP of 9.95% resulted in the 80's while a 27.66% LOLP was found in the 90's. Given these LOLP's, an average of 3.1 days per month of power outage can be expected through 1992 while between 5 and 13 days of outage should occur in the later 1990's.

Total generation falls an average of 7% throughout the study, declining over time to 83% of the base case generation. Nuclear generation again fell to 55% base case generation.

Nuclear power contributes over 40% of total generation until 1987 when the first of the Surry units is lost. Until the mid-90's, nuclear generation is still responsible for over 1/5 of total power and then declines slightly until 1998 when the last of the nuclear units are shutdown.

The most probable of the scenarios, Scenario 5, is the transshipment of spent fuel from the Surry to North Anna facility. Reracking of the North Anna pool was again assumed in this scenario. Transshipment would allow Surry to remain operational until 1991. North Anna, however would also cease operation in 1991.

Nuclear generation remains unchanged from the base case values until 1992 when it is lost entirely. As a result, total generation falls an average of 20% throughout the 1990's. The use of pumped storage is almost cut in half due to the lack of base loaded generation. Coal fired units take on a much larger share of total generation, and provide over 70% of the power each year after 1993, producing over 86% of total generation in 2001. Generation from the other units also increases, but not to the extent of coal.

The average capacity factor increased 3 percentage points from the base case to 63.1%. Capacity factors of individual units falling on the upper end of the loading scale increased in the 1990's to the same extent as did values in the worst case scenario. After 1991, the transshipment scenario becomes identical to the worst case scenario as nuclear capacity is lost completely.

The average reserve margin over the first half of the study is slightly less than the base case average. It drops to the level of the worst case scenario over the remainder of the study. On the whole, this scenario ranks second best with reserves averaging 13.2% of capacity. Should a scenario be modeled lifting the assumption of shutdown at loss of full core reserve, the overall reserve margin would probably rise to a level slightly higher than Scenario 4 (NA pool expansion, forced shutdown) which has the highest reserve margin (15.76%) of the scenarios analyzed.

The same reasoning may or may not be true with the loss-of-load probability. Although the LOLP averages only 6.4% over the beginning of the study, the extremely high LOLP's in the late 1990's push the overall average up to 25-1/2%. This ranks the scenario third with the best scenario holding an 18.8% average LOLP. The best scenario again is the pool expansion scenario given shutdown occuring when no storage space remains.

Unserved energy after 1991 increases drastically, increasing over 300% each year and up to 620% in one year. Average system costs rise between 30 and 50% once nuclear capacity is lost. Fuel costs increase an average of 16% over base case costs.

Model Description

Capacity Analysis Model

The Capacity Analysis model (CAm) selects the most economical mix of new generating plants required to meet future needs for power. The total demand for power is comprised of annual peak demands plus a reserve. The load duration curves input to the model are supplied by another model, the Load Analysis model (LAm). This model projects annual curves based on historical load patterns and utility forecasts of both peak load and energy consumptions.

In order to determine the optimal (least costly) expansion plan, a large number of possible mixes of expansion units must be evaluated. CAm uses a Linear Program (LP) to develop the sets of expansion candidates and evaluate their cost. A Linear Program is composed of an objective function and a set of constraints. Each of these takes the form of a linear equation. The program seeks to minimize or maximize the objective function subject to the constraints imposed.

In CAm's application of the LP, the total system cost is represented by the objective function, which the program minimizes. This cost is comprised of new plant capital costs, fixed O&M costs, fuel costs, and variable non-fuel costs. The capital costs and fixed O&M costs are calculated as the cost per MW times the size of the plant. A fixed charge rate is also applied to the capital cost. The fuel costs and variable O&M costs are based on the generation, where generation is calculated as capacity times duration of use (in hours). Both existing plant costs and new plant costs are considered in calculating the total system cost.

The constraints used by the program fall into four major categories: demand, reliability, plant availability, and unit operating characteristics. The demand constraints require that 1) generation must meet demand, and 2) additional power must be generated if pumped storage is to be used. The reliability constraints impose a reserve requirement on the system. Three methods are available to calculate the reserve: minimum reserve margin, loss-of-load probability, and maximum reserve margin. The method employed in this study was that of minimum reserve, where a single percentage was input as the reserve margin. Plant availability constraints limit the number of new plants and the years in which they may be put on line. Unit operating characteristics take into account forced outages and the percentage of time a plant may be available for use.

Pumped storage units are treated differently than other capacity groups. The energy required for pumping, adjusted for an efficiency factor, is added to the system demand. Pumped storage generation will be dispatched at points of high demand and pumping will occur at points of low demand. Annual load duration curves are input to the model to describe demand. Nuclear units typically meet the base load, or that portion of demand which remains essentially constant. Coal units are dispatched to meet the middle portion of the load. The oil units and peakers are used only to meet peak demand and are the units which are displaced by the pumped storage units. CAm is designed such that 1) a given fuel type to be used for pumping and will not be used for generation, and 2) pumping and generation will never occur at the same time.

Production Cost Simulation Model

The Production Cost Simulation model (PCS) calculates a utility's projected energy generation and fuel consumption on a monthly, quarterly, and annual basis. System load parameters such as reserve margin, capacity factor, unserved energy and loss of load probability are also determined by the model. The model requires monthly data inputs concerning each unit's operating characteristics. Such data include capacities, equivalent availabilities, heat rates, fuel prices and dispatching order. Monthly load duration curves are also required. These curves are output of the Load Analysis model for direct input to PCS.

The probabilistic simulation used in the PCS model for production costing and reliability calculations was originally developed by Baleriaux et al. The load duration curve required by this method is expressed as a piece-wise linear function - in PCS it is represented by fifty points.

The purpose of the probabilistic simulation is to predict the generations of the system's individual units subject to the fact that all units may not be available at any one time. The combination of units not available for operation cannot be predicted with certainty due to random forced outages. Each of these combinations, however, may be assigned a weighted probability of occurrence. Taking this into account, the probabilistic simulation determines the expected generation of each unit given the probabilities that the units loaded prior to it may be randomly forced out.

A plant is generally loaded in more than one step. The Production Cost Simulation model allows blocking of three steps. This allows the program to simulate the backing off of base-loaded units to meet minimum loads. The first loading blocks of the least costly units are dispatched first to meet demand.

PCS also has the capability to model pumped storage. The simulation determines the optimal monthly pumping which can occur and then adjusts pumped generation to meet certain constraints. These constraints are: 1) the cost of the marginal pumping unit must not exceed cost of last unit displaced, 2) total energy for pumping should not exceed a specified limit, 3) if no offloading occurs, the cost of the marginal pumping unit must not exceed the cost of purchased power displaced, and 4) the same block may not be used for both pumping and offloading.

TABLE 1

Reliability Measures

	Reserve Margin (in %)			LOLP (in %)		
	1984-92	1993-2001	1984-2001	1984-92	1993-2001	1984-2001
Base Case	35.74	24.55	30.14	4.65	9.88	7.27
Scenario 1	12.28	(5.43)	3.43	21.29	44.49	32.89
Scenario 2	19.67	(5.43)	7.12	16.09	44.49	30.29
Scenario 3	18.79	3.90	11.35	13.21	30.96	22.09
Scenario 4	25.05	6.47	15.76	9.95	27.66	18.81
Scenario 5	31.83	(5.43)	13.20	6.41	44.49	25.45

OPTIONS FOR COMPUTATIONAL EFFICIENCY IMPROVEMENT OF CAPACITY EXPANSION OPTIMIZATION

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Abstract

The computing time needed to obtain the optimum expansion plan for an electric generating system is an important factor. In this paper, several options to improve the computational efficiency in electric capacity expansion optimization are presented. The most desirable option is to obtain a benchmark solution from year-to-year optimization with static buffer period and then use this benchmark solution as the initial guess for dynamic programming optimization.

1. Introduction

The large amount of computing cost needed to achieve an optimum expansion plan is a great limitation to the users of any global optimization models. Long term expansion planning contains many imprecise variables such as escalation rate, interest rate, discount rate, load growth, etc. It is thus imperative to study many possible scenarios to arrive at an optimum system expansion plan. So any significant improvement on computing efficiency is highly desirable to the capacity expansion analysts. The authors in this paper addressed the options to decrease the computing time. These are 1) decreasing the number of iterations required to obtain an expansion plan by dynamic programming, 2) decreasing the end effects, and 3) decreasing the number of periods used to represent a year. The authors enhanced the Capacity Expansion and Reliability Evaluation System (CERES) program [1] to improve the computational efficiency. The results and discussions of this paper are based on the output obtained from the enhanced version of the CERES program.

The number of iterations required to obtain an optimum expansion plan can be reduced by supplying an initial expansion schedule which lies in the neighborhood of the optimum. The initial guess can be obtained from 1) hand calculations, 2) inexpensive expansion planning programs like OGP [2], and 3) using the year-to-year optimization option of a global optimization program. Hand calculations involve an enormous amount of time to get an initial guess, and also involve the risk of human error. Using a second program to get an initial guess involves the preparation of data in two different forms and the inconsistency between dissimilar modeling methods. In order to obtain a benchmark solution, the authors enhanced the CERES program by incorporating the year-to-year optimization with a user specified static buffer period. During the static buffer period, the operation of the system is assumed to continue at no load growth. The operating costs at the decision year are escalated and discounted to find the costs over the buffer period. The objective function is the total costs computed over a time horizon which includes both the decision year and the buffer period.

In the expansion planning, end effects arise because near the end of the study horizon the decision for new generation is made on the basis of future capital and operating costs of only a very few years. The effects of fuel escalation rates are not adequately accounted for when they are considered for such a short future. Reduction of end effects increases the useful length of the study period and hence improves computing efficiency. To increase the computing efficiency by reducing the end effects, the authors modified the dynamic programming module of the CERES program to incorporate a user specified buffer period at the end of the study horizon.

Reduction of the number of periods representing a year reduces computing time significantly, but it produces load which is deviated from the real load pattern. Although significant amount of computing cost can be saved, care must be taken not to sacrifice the accuracy.

The authors in this paper stressed the use of a benchmark solution, obtained from year-to-year optimization in the dynamic programming optimization. The effect of the length of buffer periods on both year-to-year optimization and dynamic programming optimization is studied. The authors also compared the solution obtained from the year-to-year optimization and the dynamic otpimization.

2. Results and Discussions

Expansion plans, from yearly optimization, with static buffer periods of 5 and 10 years and with no buffer period, are investigated. The results are shown in fig. 1. The amount of capacity added to the system in the case of 5- and 10-year buffer periods are almost identical. This indicates that a static buffer period of 5 years is sufficient for the yearly optimization. The authors noted, however, that there is a significant difference in the capacity addition, particularly in the early years of planning, for the yearly optimization with no static buffer period and that with a static buffer period of 5 years.

From dynamic programming optimization, the capacity additions with static buffer periods of 5 and 10 years and with no buffer period are shown in figure 2. As can be seen in figure 2, a static buffer period of 5 years is an acceptable choice for the dynamic programming optimization. However, a significant difference in capacity addition exists between cases of no static buffer period and a static buffer period of 5 years. Table 1 compares the expansion plans produced by these two cases. There is a signficant difference in the expansion plan for the last few years. This difference depends on the size, operating and capital costs of the expansion candidates.

Table 2 shows the expansion plans produced by dynamic programming optimization and yearly optimization, and figure 3 shows their capacity additions.

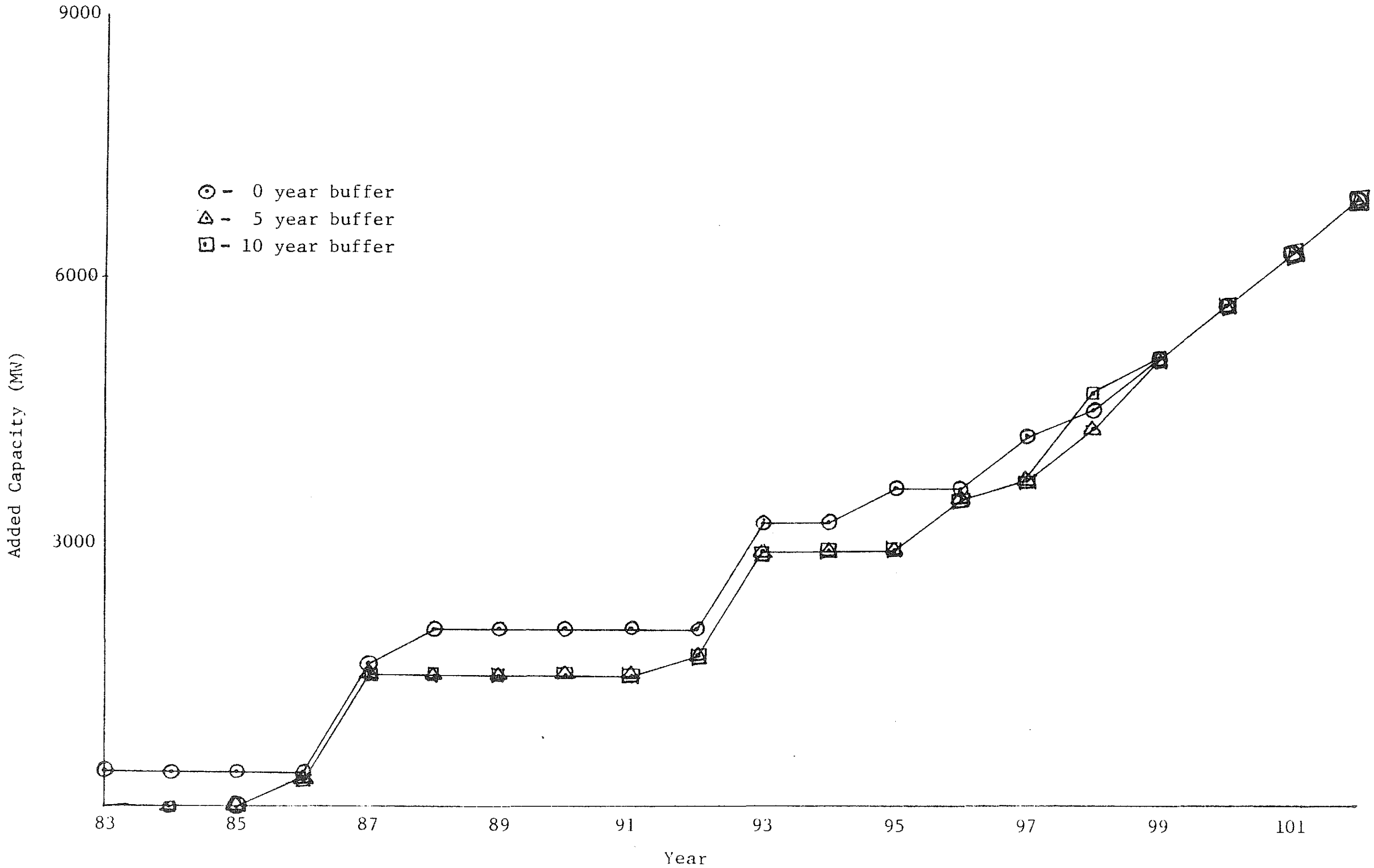

Fig. 1 Comparison Between Different Static Buffer Periods of Myopic Optimization

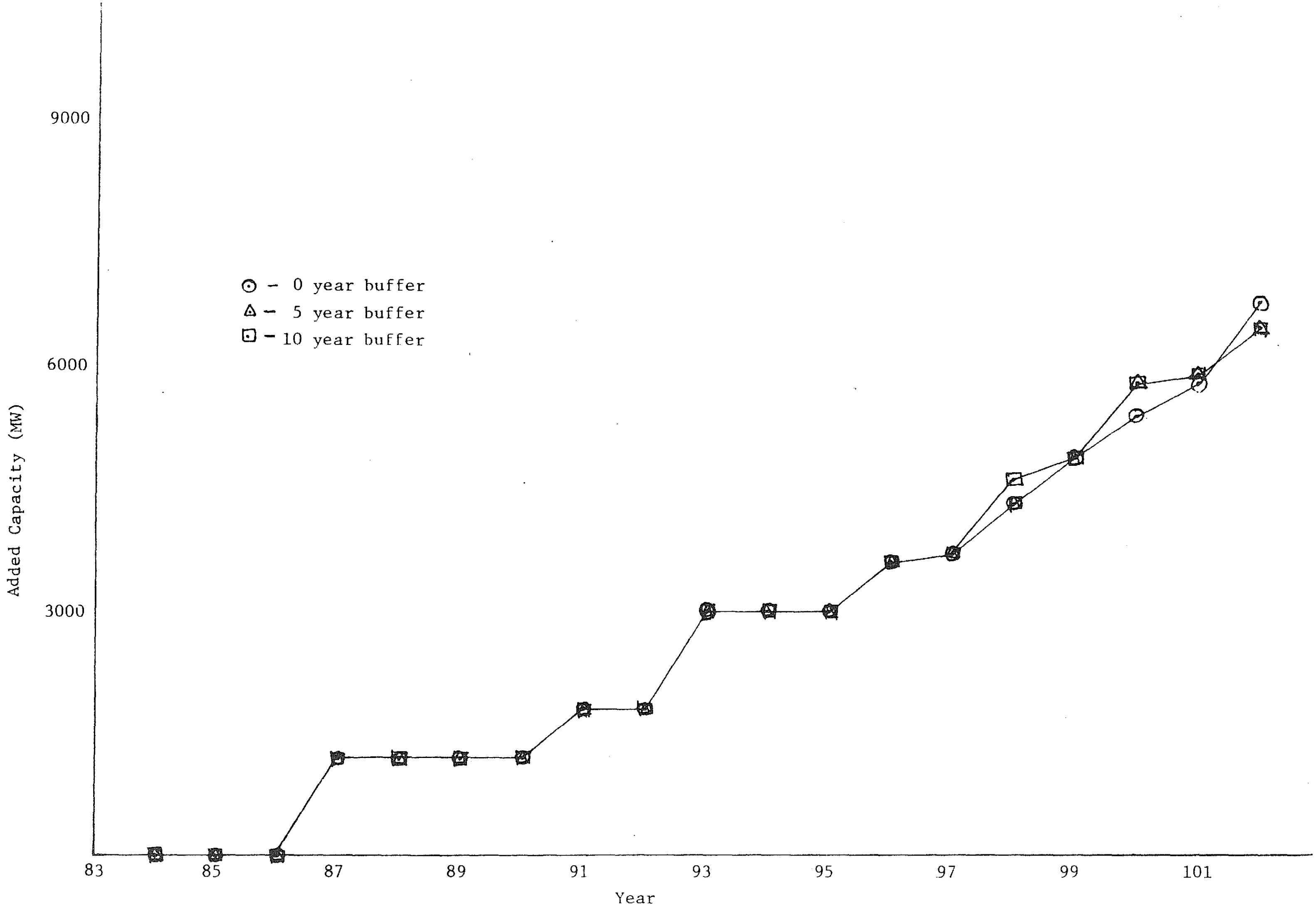

Fig. 2 Comparison Between Different Static Buffer Periods of Dynamic Optimization

TABLE 1. COMPARISON OF EXPANSION PLANS USING DYNAMIC PROGRAMMING OPTIMIZATION WITH NO BUFFER AND WITH BUFFER OF 5 YEARS

YEAR	DYNAMIC PROGRAMMING OPTIMIZATION WITH NO BUFFER PERIOD			5 YEAR BUFFER PERIOD		
	N1200+	C100++	GT 600+++	N1200	C100	GT 600
1983	0	0	0	0	0	0
1984	0	0	0	0	0	0
1985	0	0	0	0	0	0
1986	0	0	0	0	0	0
1987	1	0	0	1	0	0
1988	0	0	0	0	0	0
1989	0	0	0	0	0	0
1990	0	0	0	0	0	0
1991	0	0	1	0	0	1
1992	0	0	0	0	0	0
1993	1	0	0	1	0	0
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	0	1	0	0	1
1997	0	1	0	0	1	0
1998	0	0	1	0	0	1
1999	0	0	1	0	0	1
2000	0	0	1	0	3	1
2001	0	4	0	0	1	0
2002	0	10	0	0	0	1
TOTAL	2	15	5	2	5	6

+ 1200 MW Nuclear Plant
++ 100 MW Coal Plant
+++ 600 MW Gas Turbine Plant

TABLE 2. COMPARISON OF EXPANSION PLANS USING DYNAMIC PROGRAMMING OPTIMIZATION AND MYOPIC OPTIMIZATION

	DYNAMIC WITH 5 YR BUFFER			MYOPIC WITH 5 YR BUFFER		
YEAR	N1200	C100	GT600	N1200	C100	GT600
1983	0	0	0	0	0	0
1984	0	0	0	0	0	0
1985	0	0	0	0	0	0
1986	0	0	0	0	3	0
1987	1	0	0	1	0	0
1988	0	0	0	0	0	0
1989	0	0	0	0	0	0
1990	0	0	0	0	0	0
1991	0	0	1	0	0	0
1992	0	0	0	0	2	0
1993	1	0	0	1	0	0
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	0	1	0	0	1
1997	0	1	0	0	2	0
1998	0	0	1	0	6	0
1999	0	0	1	0	2	1
2000	0	3	1	0	0	1
2001	0	1	0	0	0	1
2002	0	0	1	0	0	1
TOTAL	2	5	6	2	15	5

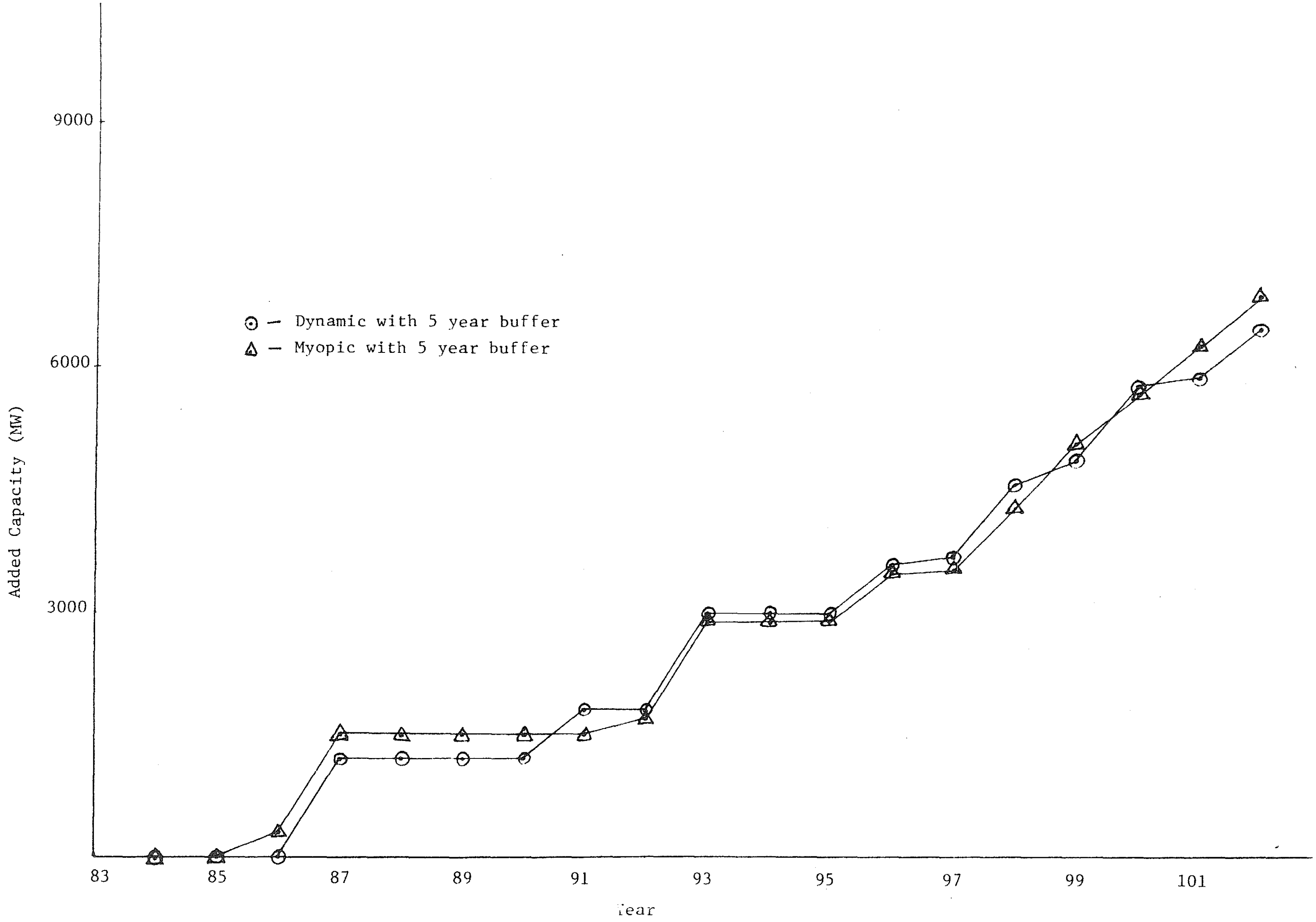

Fig. 3 Comparison Between Dynamic and Myopic Optimization

Table 2 and figure 3 indicate that yearly optimization gives an expansion plan which is very close to that given by the dynamic programming optimization. The authors found that the computing time for dynamic programming optimization is more than two and one-half times higher than that for year-to-year optimization. Thus, an initial guess of expansion plan can be obtained at a much cheaper cost using yearly optimization with a static buffer period of 5 years. This benchmark solution can then be used as the starting point for global optimization to obtain an expansion plan with fewer number of iterations.

The authors found that about 50% computing time can be saved if one period, instead of four, is used to represent a year. Figures 4 and 5 compare the capacity additions for these two cases with load growth of 4% and 2%, respectively. From these figures it can be concluded that the reduction of the number of periods used to represent a year is associated with the loss of accuracy.

3. Conclusion

It should be noted that although there are several options to improve the computational efficiency, all of the options addressed in this paper may not be attractive to the user who is concerned about the loss of accuracy. Among other options, one is to reduce the number of capacity blocks. Lubbers [3] achieved a substantial savings on computing time with a little influence of expansion plan. Using a benchmark solution from the year-to-year optimization program as an initial guess in the dynamic programming optimization should be the most desirable option.

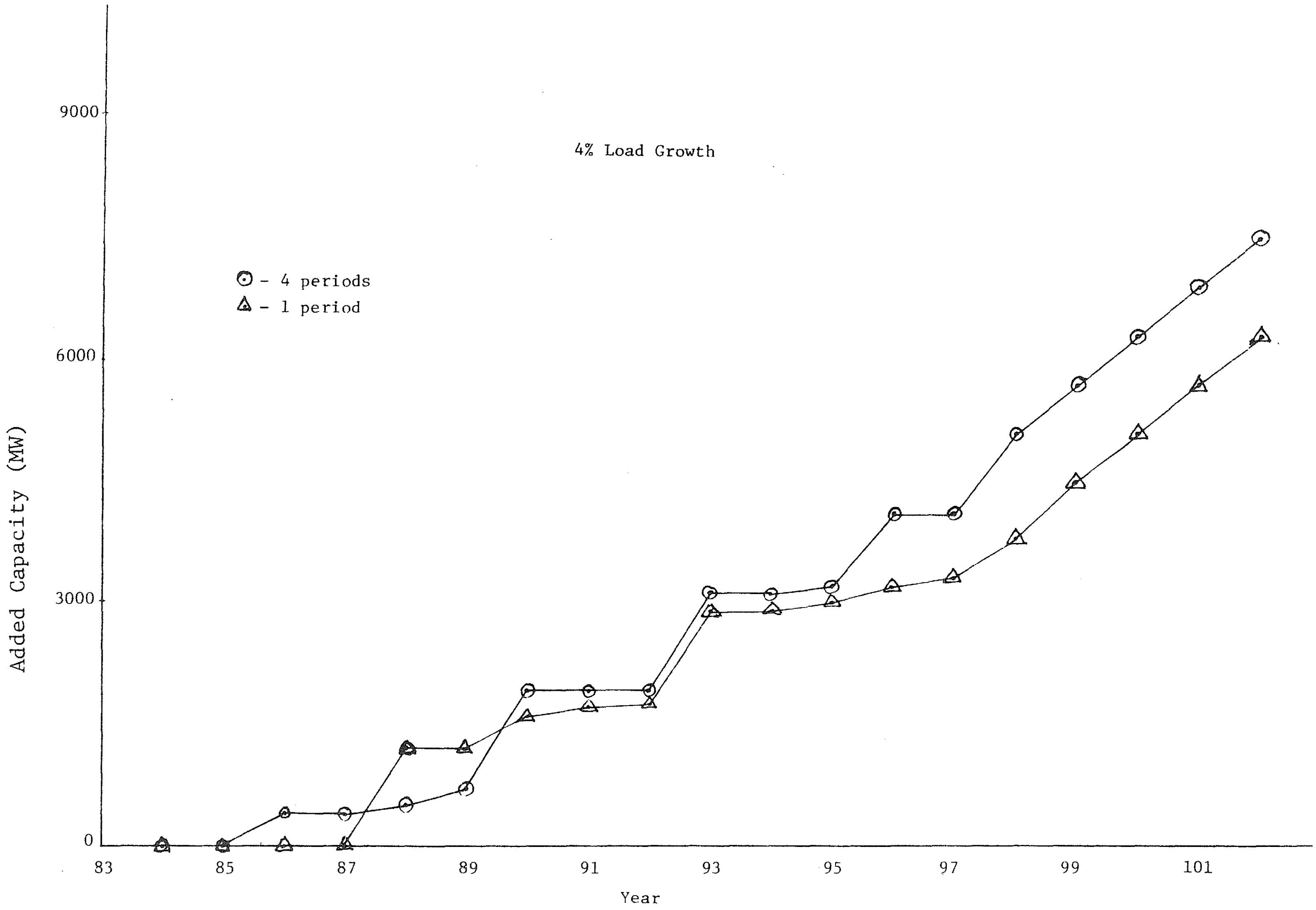

Fig. 4 Comparison Between 1 Period and 4 Periods a Year

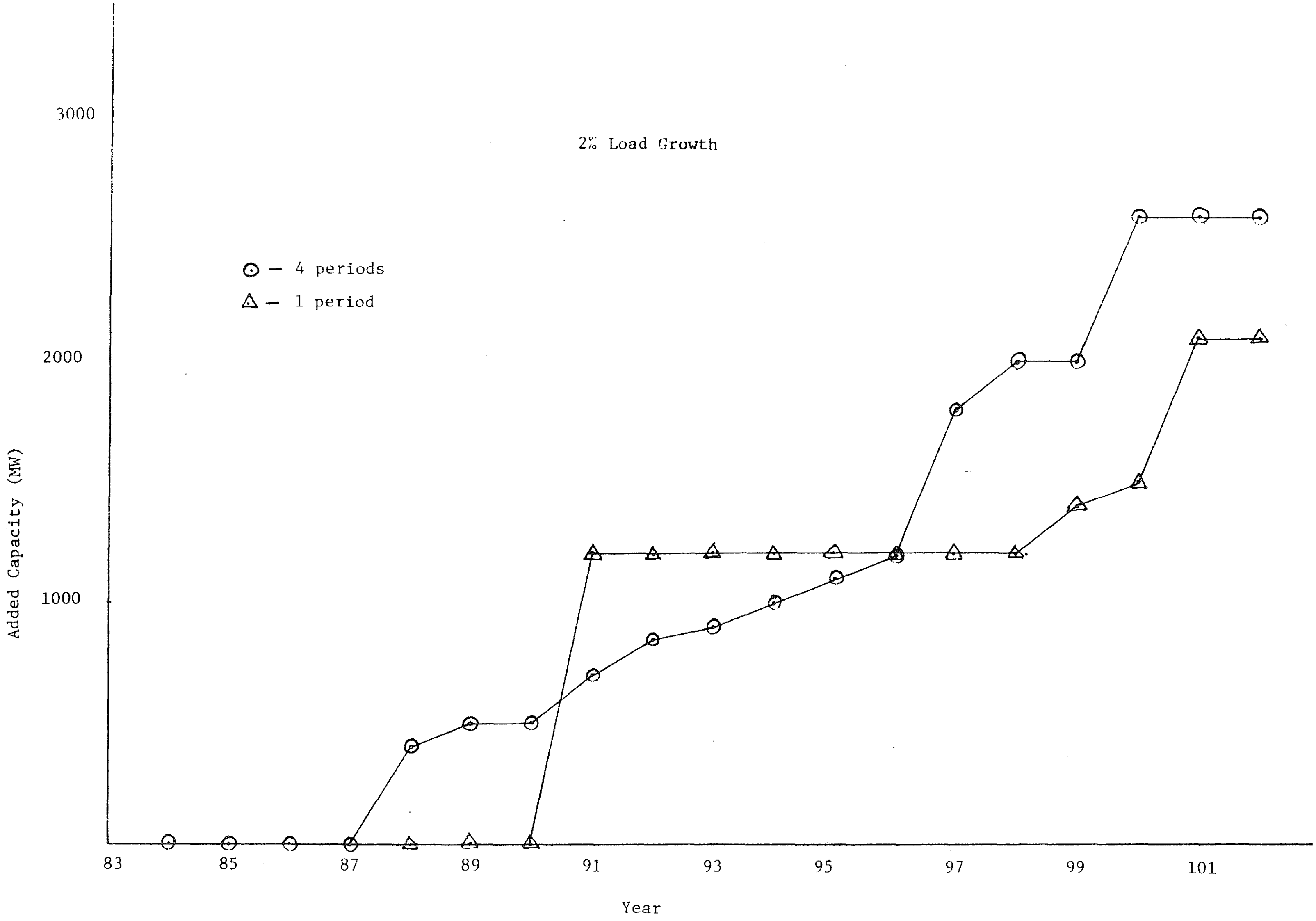

Figure 5 Comparison Between 1 Period and 4 Periods a Year

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THE SENSITIVITY OF MARGINAL CAPACITY COST TO THE NUMBER OF POTENTIAL EXPANSION UNITS

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Capacity expansion models can be useful tools for estimating the marginal capacity cost of electric generation systems. The Capacity Expansion and Reliability Evaluation System (CERES) is one of these models (1). The procedure usually recommended for calculating marginal capacity cost requires at least two optimal expansion plans differing only by the projected growth rate of demand. The difference in the value of the objective function between the two runs provides the basic data for the marginal capacity cost calculation. Since the choice space that represents all possible expansion units from which the optimal expansion plans are derived is discontinuous, the choices are lumpy and discrete jumps in the value of the objective functions are possible. Thus, the number and capacity of potential expansion units can affect the overall cost of the optimal expansion plan and the concomitant value of the marginal capacity cost. The purpose of this paper is to examine the sensitivity of marginal capacity cost to the number of potential expansion units. Computer simulations of CERES were designed to evaluate the behavior of both the value of the objective function and the value of the marginal capacity cost as the number of potential expansion units increase. The observed behaviors of the value of the objective function and marginal capacity cost were compared to the behaviors that theory would suggest.

From a purely theoretical viewpoint, the value of the objective function is expected to decline and asymptotically approach some constant value as the number of potential expansion units increases. This behavior is depicted in figure 1A. It must be recognized, however, that the discreteness of the plant choices as well as the limitations of the computational algorithm in CERES (or any other generation planning model) may cause deviations from this expected behavior.

Expectations concerning the behavior of the value of marginal capacity cost are more difficult to formulate. Given the objective function in CERES, the value of which represents the future total cost of construction and operation, it is not clear how the computed marginal capacity cost will behave. If the objective of the optimization was to minimize the marginal capacity cost, marginal capacity cost would be expected to decline and asymptotically approach some value as the number of potential expansion units increased. But, the optimization is not based on this objective. Instead, marginal capacity cost is calculated using two minimum cost expansion plans from CERES each of which reflect different growth rates. The formula

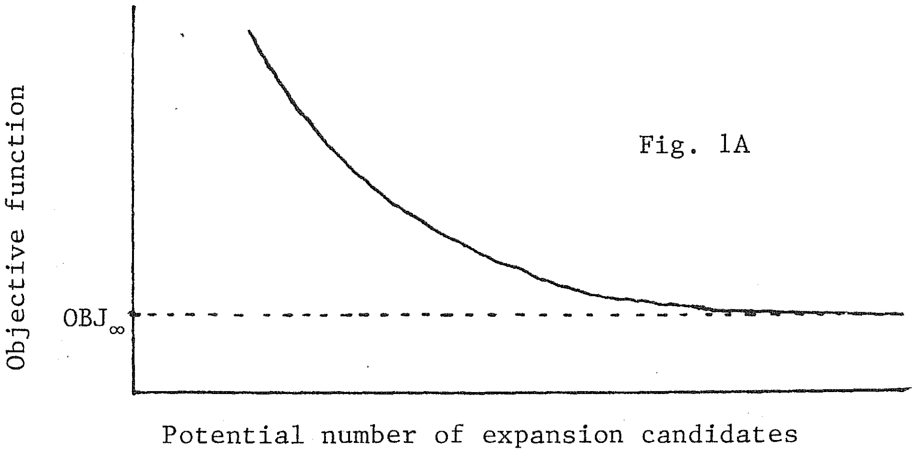

Fig. 1A

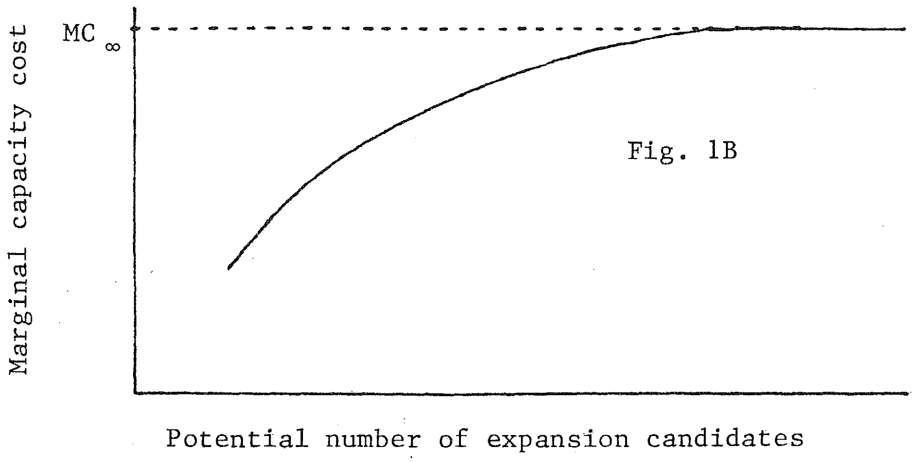

Fig. 1B

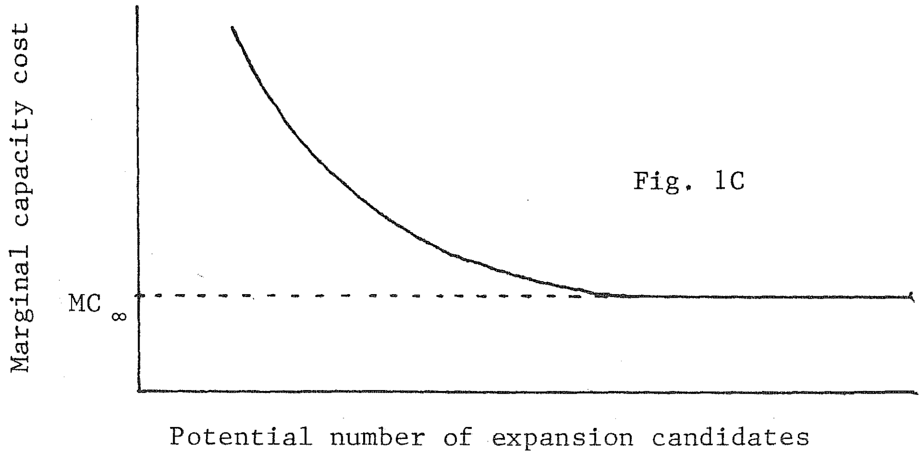

Fig. 1C

for marginal capacity cost (MCC) is given by (2):

$$\text{MCC} = \frac{\sum_t (C_t' - C_t) + (O_t' - O_t)}{\sum_t (K_t - K_t')} \left(r + \frac{1}{L}\right)$$

where $(C_t - C_t')$ is the present value of the change in the total cost of construction for the entire planning horizon of T years as a result of a change in the growth rate of demand. $(O_t - O_t)$ is the present value of the change in running cost for the entire planning horizon as a result of a change in the growth rate of demand and $(K_t - K_t)$ is the corresponding change in installed capacity. The last parenthetical expression $(r + \frac{1}{L})$ annualizes this change in costs per unit of capacity. r is the cost of capital, while $\frac{1}{L}$ yields a straight-line depreciation rate given a composite life of L years for all newly installed units. Given this computation for marginal capacity cost, it is hypothesized that marginal capacity cost may increase or decline to an asymptotic value with respect to the number of potential expansion units. These possible behaviors are depicted in figures 1B and 1C. Again, it must be recognized that the discreteness of the choice space and limitations of the computational algorithm in CERES may cause deviations from this expected behavior.

The basic experiment consisted of performing nine runs of CERES. Three groups of runs were given the choice of two, three, or four potential expansions. Each of these three groups, consisted of three runs of CERES for which the assumed growth rate of demand was 3%, 4%, and 5%, respectively. An additional six runs of CERES were performed subsequent to the basic nine runs in order to investigate some anomalous behavior in the objective function that was observed in the basic nine runs.

The basic data and assumptions for the study are presented in Exhibit 1 and Table 1. Exhibit 1 presents the basic study data inputted into CERES. Table 1 presents information regarding the four potential expansion units. All potential expansion units were assumed to be of 200 MW capacity. This was done to eliminate the effect of the capacity size from the results. One could easily view these 200 MW units as fractional values of plants of larger capacity. This assumption minimizes the effect of the lumpiness of plant size on the value of the objective function and marginal capacity cost. Each potential expansion plant is represented by a single block of capacity. Furthermore, each year was considered to be a single period for the simulations. These two assumptions helped minimize computation costs. Finally, the planning horizon was assumed to be twenty years.

The myopic optimization technique (3) option of CERES was chosen rather than the dynamic programming algorithm option. This was done to minimize computational costs. As discussed below, this choice was not without consequences.

Exhibit 1. Basic Data Used in The Study

Existing System Capacity	=	11500 MW
Annual Load Growth Rate	=	3 - 5%
No. of Periods in a Year	=	1
Annual Load Factor	=	60%
Peak Loan in the First Year	=	8211.6 MW
Critical Lolp	=	0.002
Maximum Reserve Margin	=	50%
Present Worth Discount Rate	=	15%

Table 1. Input Date For Expansion Plants

Data	Plant Type Code			
Item	4	6	7	8
Capacity (MW)	200.00	200.00	200.00	200.00
Maint. Outg. (D/YR)	34	30	39	21
Forced Outg.	0.07	0.05	0.08	0.04
Cap. Cost ($/KW)	991.07	939.28	1125.00	825.00
Fuel Cost ($/MWH)	17.10	17.90	14.70	19.70
Fixed O.M.C. ($/KW/YR)	8.93	10.72	15.00	14.64
Var. O.M.C. ($/MWH)	1.10	1.40	1.30	1.40
Economic Life (YR)	35	35	35	35
Cap. Cost Esc. Rate	0.10	0.10	0.10	0.10
Fuel Cost Esc. Rate	0.10	0.10	0.10	0.10

Each of the two plant runs were initially given the choice of expansion units 7 and 6 from table 1. The three plant runs were given the choice of plants 7, 6, and 4 from table 1, while the four plant run was given the choice of all plants in table 1. The results for the objective function are presented in table 2, while the results for the computation of marginal capacity cost are presented in table 3.

The behavior of the value of the objective function was as expected for each growth rate case. However, the limited number of observations does not allow any conclusions to be drawn with respect to an asymptotic value. The results are depicted in figure 2 by the solid lines through the three observed values.

As noted earlier, six additional runs of CERES were performed - two for each growth case. Since all three plants were chosen in the three plant case, it raised the question which combinations of two plants from these three would yield the lowest value of the objective function in the two plant case. The additional runs used two plant combinations 7 and 4, and 6 and 4. One two plant combination (6 and 4), not originally considered, yielded a lower value for the objective function in all three growth cases. More importantly, this lower value for the two plant case cause the value of the objective function to increase as the number of potential expansion units increased from two to three plants. This behavior is depicted by the dotted lines in figure 2. The behavior deviates from that expected.

A detailed examination of the CERES output disclosed that this resulted from the difference between the objective function used for myopic optimization and the actual cost function it seeks to approximate which is reported in the results. It was concluded the anomalous behavior of the objective function is a consequence of the use of the myopic optimization technique, and that one should carefully examine all possible combinations of potential expansion units when using this optimization technique.

The basic study results for the objective function enabled the calculation of two scenarios for marginal capacity cost. Using the 4% load growth case as a base, the marginal capacity cost for a 1% increment and 1% decrement in the growth rate of demand was computed. The results are reported in table 3 and presented in figure 3.

In the 1% load growth case, the value of marginal capacity cost behaved as expected. In increased as the number of potential expansion units increase. Again, due to the limited number of observations, no conclusion with respect to an asymptotic value could be drawn.

In the 1% load decrement case, however, the behavior of marginal cost was erratic. It increased and then declined as the number of potential expansion units increased. This conclusion could be extended to both cases for marginal capacity costs when the anomalous behavior of the objective function due to the use of myopic optimization was considered. This latter result led to several conclusions.

Table 2. The Objective Function* for Different Number of Potential Expansion Units

Annual Load Growth Rate	Objective Function (Millions of Constant Dollars) 2 Plants	3 Plants	4 Plants
3%	15059.320 (7,4) 15004.121 (7,6) 14720.006 (6,4)	14770.020 (7,6,4)	14564.262 (8,7,6,4)
4%	17601,504 (7,4) 17505,266 (7,6) 17162.738 (6,4)	17340,551 (7,6,4)	17106,547 (8,7,6,4)
5%	20354.254 (7,4) 20223.480 (7,6) 19802.414 (6,4)	20149,426 (7,6,4)	19899.133 (8,7,6,4)

*The quantities in parenthesis represent expansion plant combinations (see Exhibit 1)

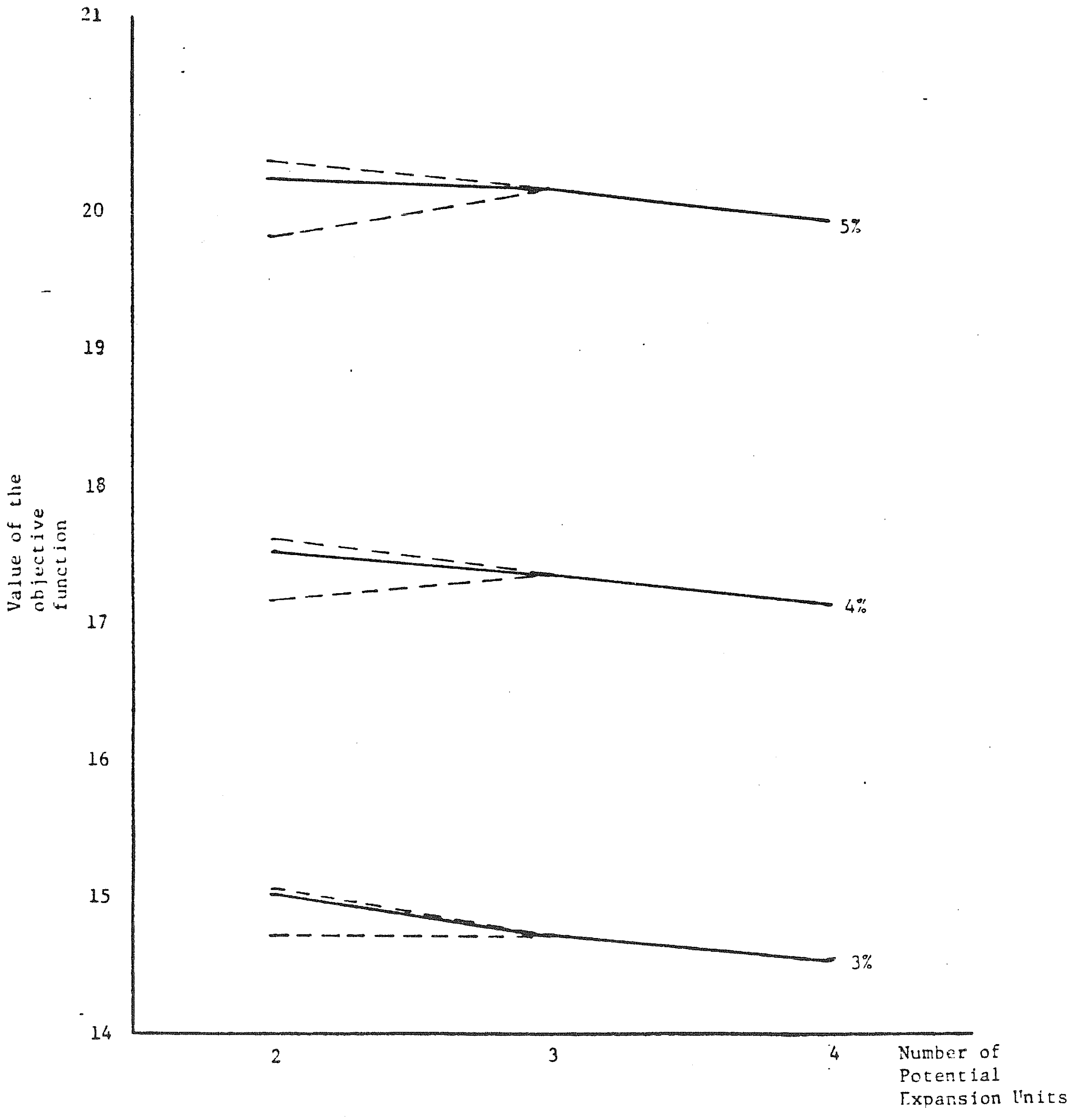

Figure 2. Behavior of Objective Function for Different Number of Potential Expansion Units

Table 3

Marginal Capacity Cost for Different Number of Potential Expansion Units

Change in Annual Growth Rate	Number of Potential Expansion Candidates	Change in Capacity (MW)	Change in Cost Per ($/KW)	Marginal Capacity Cost ($/KW)
1%	2	3600	978.39	155.14
		3600	959.39	152.13
		3600	922.76	146.32
	3	3800	947.85	150.30
	4	3800	925.56	146.70
-1%	2	3200	1018.09	161.44
		3200	1003.89	159.19
		3200	993.48	157.54
	3	3000	1088.57	172.62
	4	3000	1038.08	164.61

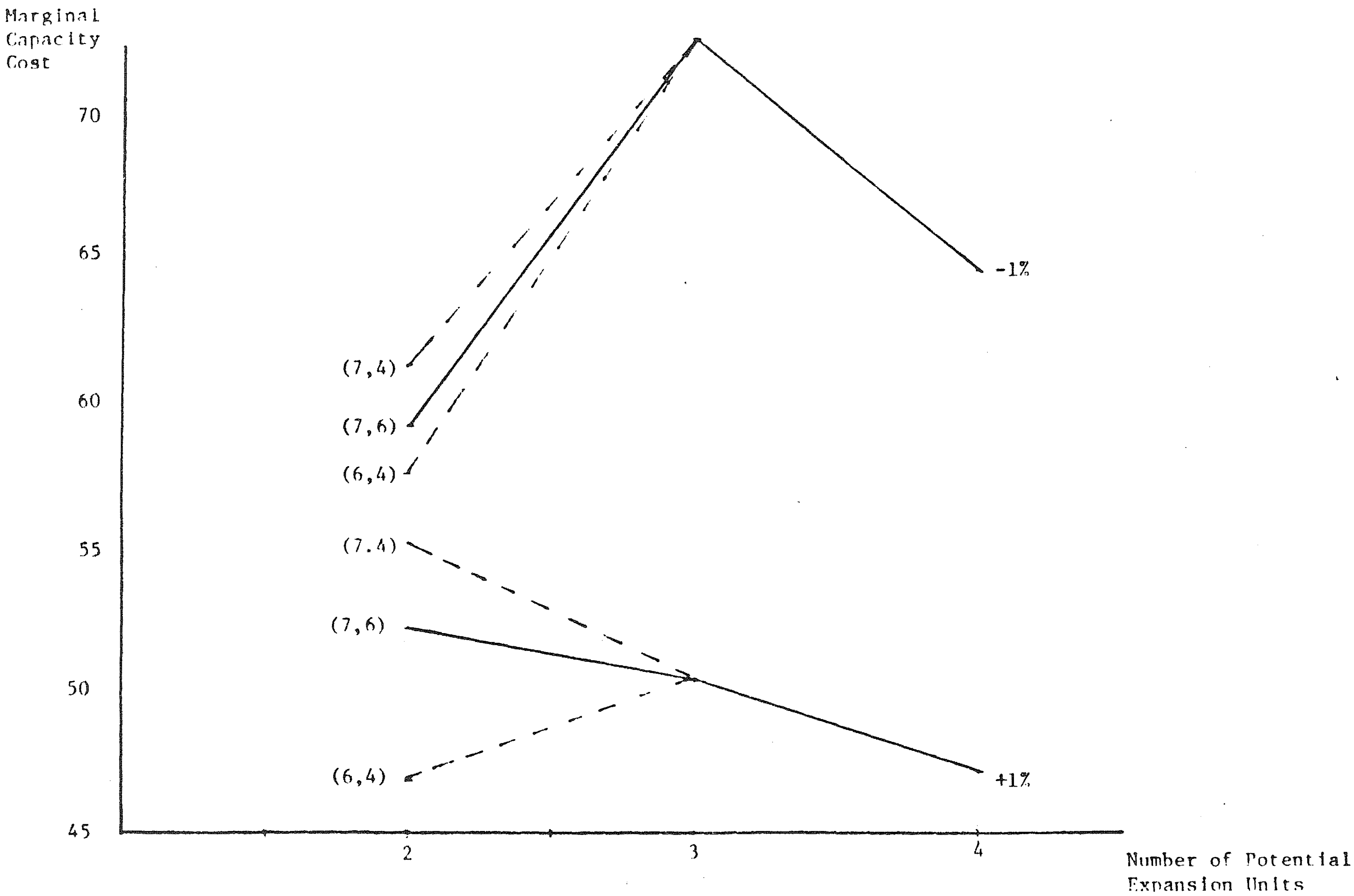

Figure 3. Behavior of Marginal Capacity Costs for Different
Number of Potential Expansion Units

The use of capacity expansion models using integer techniques for computing marginal capacity costs needs further investigation. Lines of inquiry should pursue the following paths:

1. One should investigate fully all possible combinations of potential expansion units when computing marginal capacity costs;

2. The efficacy of the myopic optimization technique, as embodied in CERES and other capacity planning models, with respect to the number of potential expansion units needs further investigation;

3. The relationship between the objective function definition used to find the optimal expansion plan and the marginal capacity cost derived from such plans needs further investigation. Analytical techniques may be preferable for further study.

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A PROBABILISTIC OPTIMIZATION METHOD FOR THE BRAZILIAN POWER SYSTEM BASED ON MARGINAL COST CONCEPTS

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1. Introduction

The Brazilian electric power system is predominantly hydraulic, with thermal power representing less than 10% of its generating capacity. The system, as a whole, is dominated by enormous hydro plants which offer an exceptional capability of stream flow regularization. As a measure of this regularization capability, one can take the so-called critical period of emptying. Its value in the aggregated hydro system is typically so much as 4 to 5 years.

The regularization capability makes it possible to accumulate the water inflow in rainy periods for future use in dry periods. As a consequence, a significant part of the investment in plants is made to guarantee the supply of energy over a long period of time. This money has little to do with the instantaneous power supply, limited by the available capacity in generation and transmission equipment.

Due to this characteristic, the planning of the generating system operation and expansion is carried out considering the power and energy components separately. In this work, only the energy component will be addressed, which is the most costly in the Brazilian power system.

Despite the system's great regularization capability, the hydro power predominance makes the generation capacity highly dependent on the hydrological conditions. As a consequence, a main problem in the planning of the Brazilian production system is the conjunction of the uncertainty in hydro generation to load requirements, complementary thermal generation and system expansion in an overall optimization philosophy. To handle this problem, FURNAS has developed a computerized probabilistic optimization method based on marginal cost concepts.

This optimization method determines the optimal balance of fuel, shortage and investment expenditures, while simultaneously considering the revenues from non guaranteed deliveries (secondary loads). Given the guaranteed (firm) load forecast, the system configuration and the outage cost, the method defines the optimal strategy of thermal generation and non guaranteed deliveries, as well as the guaranteed load at which the system ought to be expanded. The combined operation and expansion plan so obtained minimizes the total expected discounted cost of fuels, shortages and investments minus the revenue from non guaranteed deliveries.

Sections 2 and 3 of this paper present a description of the probabilistic optimization method proposed. This method is then used to evaluate the deterministic supply criterion currently in use in Brazil for operation and expansion planning. This evaluation, described in section 4, consists of the determination of the outage cost and risk of shortage implicitly assumed in the deterministic method. The conclusions follow in section 5.

2. The Probabilistic Operation Model

The operation model proposed is based on the notion of a marginal water value. The reasoning behind it is that, given the operating strategy and expansion plan, a marginal kWh added to the stored energy will have one of the following destinies:

- will be spilled;

- will replace thermal generation;

- will replace a shortage.

If the marginal kWh stored overflows, it has no economic value to the system; if it replaces thermal generation, its economic value is the cost of the fuel saved; if it substitutes a shortage, its economic value is the shortage cost.

Thus, the expected value of the marginal kWh stored is the weighted sum of the discounted value attributed to each of its possible destinies. The weights are the probabilities of occurrence of each of those final destinies. The optimal operating strategy for the complementary thermal generation and non guaranteed load deliveries may be expressed as follows: thermal plants will be operated above their minimal operating level whenever their incremental generation cost is inferior to the expected value of the marginal kWh stored; non guaranteed loads will be attended whenever their shortage cost (a certain price limit previously stipulated) is superior to the expected marginal value of the energy stored.

Given the principles so far expounded, an operation planning model has been developed, based on the following assumptions:

a) The set of reservoirs in the system is represented by a single reservoir, called the equivalent reservoir;

b) The historical series of inflows to the individual reservoirs are reduced to a single series of corresponding "energy inflow" to the system at a given month and year;

c) The "energy inflow" to the system is probabilistic, and considered to form a Markov process. The transition matrices for each month of the year are obtained by linear regression over the historical series, of the energy inflow in a given month as a function of the energy inflow in the preceeding month;

d) The state of the system at the beginning of each month is bi-dimensional; it comprises the value of the energy inflow in the previous month (an indicator of the hidrological tendency) and the value of the energy stored in the equivalent reservoir at the beginning of the month in question. The originally continuous state space is made discrete in both dimensions;

e) The shortage cost of guaranteed energy (firm load) is known and reflects the social economic costs resulting from a failure to meet the requirements. It is given in US$ per MWh.

Using the implicit dynamic programming technique, the value of the marginal stored energy is determined for each month and state of the system.

Since the optimal operating strategy for complementary thermal generation and non guaranteed deliveries is known, one can simulate the system's operation. Now, the evolution of the energy inflow and energy stored in the system form a Markov chain. Hence, the simulation will provide the probability of permanence in each of the states chosen for the implicit dynamic programming. The lower and upper limits of the storage define the shortage and overflow probabilities.

Based on these concepts, one may optionally adopt one of the following models:

- a dynamic model which represents the system's evolution in time (load, plant configuration, etc), and whose characteristic statistics (expected thermal generation, state probabilities) also change in time;

- a static model, in which the system's configuration and load are kept constant.

The static model allows the determination of the stationary state probabilities, where the values obtained in a certain month and year repeat the same month in the following year. The steady state is obtained through the Markov chain after a great number of transitions, starting from any arbitrary state.

3. The Expansion Planning Model

As previously stated, the objective of the planning method proposed is the minimization of the total expected discounted cost of system operation (mainly fuel expenditures in the thermal plants), shortage and investment minus the revenue from non guaranteed deliveries. This objective is achieved using the operation model described in the previous section to determine the guaranteed load the system ought to supply. Such approach leads to the analysis of the implications of a marginal increase in the demand for electricity. Assuming the operation and expansion plans already defined, a load increase will cause:

a) an increase in the expected thermal generation and/or shortage, if we decide to maintain the original expansion plan;

b) the bringing forward of the date of start of operation of a new plant or unit, if we choose to keep the total expected discounted cost of thermal generation, shortage and non guaranteed deliveries in the rest of the system at its previous level, always obeying the optimal operating strategy.

The operation and expansion plans are globally optimal if the incremental costs are the same in each of the cases (a) and (b).

The decision about maintaining the original expansion plan or bringing forward a new plant corresponds, in the static analysis, to considering the plant configuration being studied or this configuration augmented by a marginal portion of the expansion project.

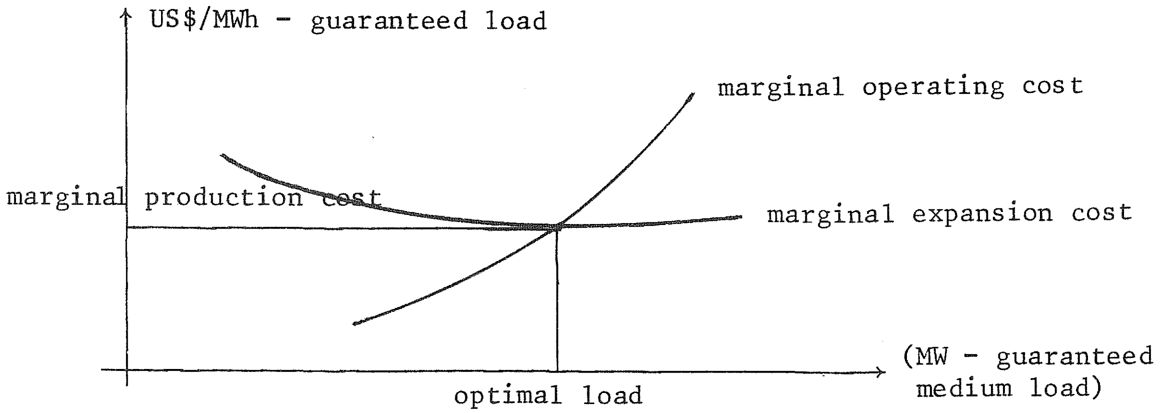
The configuration without the new plant is analysed to determine the increase in the expected value of thermal generation and shortages minus the decrease in the expected revenue from non guaranteed deliveries caused by a marginal load increment. The resulting incremental cost is obtained directly by the operation model; it is, by definition, the marginal operation cost of the system (US$/MWh - guaranteed load).

Next, the augmented configuration is analysed, the objective being to determine the marginal cost of supply using the new plant only.

Considering a small portion of the new plant, the system load is increased to such an amount that the total expected discounted cost of thermal generation and shortages minus the revenue from non guaranteed deliveries in the rest of the system is maintained constant.

The addition of the new plant to the system will lead to a cost of investment and, in the case of a thermal plant, a local expenditure of fuel. Dividing the total expected unit cost of fuel and investment in energy (US$/hour and MW - installed capacity) by the unit increment of load made possible by the new plant (MW - guaranteed medium load / MW - installed capacity) one obtains the marginal cost of expansion (US$/hour and MW - guaranteed medium load or US$/MWh - guaranteed load).

The following figure shows the evolution of the marginal operating and expansion costs for a certain system configuration and expansion project as a function of the total guaranteed (firm) load.



The intersection of the two curves defines the optimal load for the expansion of the system. This optimal expansion load establishes the economic frontier between stressing the system operation and expanding the system. When the load is below the expansion load, it is more economical to use the existing plants; when the load is higher than the expansion load, the system should be expanded as a means of avoiding excessive use of expensive thermal generation and a markedly deficitary situation. The generating cost at equilibrium could be called the marginal cost of production. Calculating this marginal production cost for every possible new project, we can find which one provides the cheapest energy and so select the best alternative of expansion.

4. Application

As an application, the probabilistic optimization method has been used to evaluate the deterministic supply criterion currently in use in Brazil. This criterion sets out that the load requirements should be met without shortages for any sequence of historical streamflows. Hence, the expansion load for a given configuration is the greatest load the system can supply, without shortages, if the historical streamflows occur.

The system configuration considered in this study was the one planned for the middle of the next decade in the Southeastern and Southern regions of Brazil. It is described in Table 1 of the Appendix. The thermal plants were aggregated in four classes: coal Rio Grande do Sul (RS), nuclear, coal Santa Catarina (SC) and coal Southeastern region (SE), according to the cost of the fuel used.

The evaluation proposed was conducted as a parametric study with respect to the outage cost.

Initially, the expansion load was obtained according to the deterministic criterion. For a given outage cost, the generating system operation was simulated to determine the maximum load that could be continuously supplied without shortages and surplus if the historical streamflows occurred. In this simulation, the system operation was carried out according to the probabilistic operating rule previously described. Figure 1 shows the expansion load as a function of the outage cost implicit in its determination.

Next, the expansion load given by the probabilistic expansion criterion was determined. This determination was made for different outage costs and alternative expansion projects. The projects considered are listed below:

Project	Marginal investment cost (US$/MWh-inst.cap.)	Marginal fuel cost (US$/MWh-generated)	Marginal expansion cost (US$/MWh-guar. load
Coal (RS)	20,3	11,9	-
Hydro 1 (*)	-	0	15
Hydro 2 (*)	-	0	20
Hydro 3 (*)	-	0	25

(*) As a hypothesis of work, the marginal expansion cost (US$/MWh-guaranteed load) was assumed given, thus defining the investment cost (US$/MWh-installed capacity) satisfying the criterion of optimal operation.

For each project and outage cost, the load for which the system's marginal operation cost equals the marginal expansion cost was determined. The curves representing the value of this expansion load as a function of the outage cost are shown in Figure 1 previously mentioned; each curve refers to a specific expansion project.

Given an expansion project, the intersection of the expansion load curves obtained using the probabilistic and deterministic criteria (Figure 1), defines the outage cost implicit in the deterministic supply criterion. This implicit outage cost and corresponding expansion load and annual frequency of shortages are shown below.

Project	Expansion load (MW-guaranteed medium load)	Implicit outage cost (US$/MWh)	Annual frequency of deficits (%)
Hydro 1	28 988	600	1.05
Hydro 2	29 091	786	1.08
Hydro 3	29 153	990	1.08
Coal RS	29 261	1 510	1.09

From these results one observes that the annual frequency of deficits remains practically constant for any expansion project chosen; the outage cost is around US$ 1000/MWh, and depends on the expansion project effectively at disposition.

5. Conclusion

The results obtained show that the present supply criterion is essentially one of fixed reliability, leading to the same risk of shortage whatever the cost of fuel or investment of the selected expansion project. As a consequence, considering that in Brazil the production costs of new plants are highly diverse, the implicit outage cost will show a change in time. This seems contradictory considering the slowness with which changes occur in load structure.

The risk level obtained was about 1% annual outage probability and the corresponding outage cost in the order of US$ 1000/MWh. In comparison to other countries, these results suggest a rather low risk level, possibly implying a more reliable supply than consumers are actually disposed to pay for.

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Table 1 - System Configuration

A - Hydroelectric Power Plants

Power Plant	Useful Storage (km^3)	Average Efficiency ($MW/m^3/s$)
Camargos	0.7	0.18
Itutinga	0.0	0.24
Furnas	17.2	0.76
Peixoto	2.5	0.34
Estreito	0.0	0.56
Jaguara	0.0	0.40
Volta Grande	0.0	0.22
Porto Colombia	0.0	0.20
Graminha	0.5	0.80
Euclides da Cunha	0.0	0.76
Limoeiro	0.0	0.21
Marimbondo	5.3	0.52
Água Vermelha	5.2	0.47
Emborcação	13.0	1.05
Nova Ponte	8.4	0.80
Miranda	0.0	0.44
Fecho da Onça	3.4	1.00
Itumbiara	12.5	0.62
Cachoeira Dourada	0.3	0.28
São Simão	5.6	0.59
Barra Bonita	2.6	0.14
Bariri	0.0	0.19
Ibitinga	0.0	0.19
Promissão	1.4	0.20
Nova Avanhandava	0.4	0.26
Ilha Solteira	16.4	0.38
Jupiá	0.0	0.20
Jurumirim	3.0	0.28
Xavantes	3.0	0.62
Lucas N. Garcez	0.0	0.15
Capivara	5.7	0.36
Taquaruçu	0.0	0.23
Rosana	0.0	0.17
Itaipu	0.0	1.08
Foz do Areia	4.2	1.12
Segredo Alto	0.4	0.88
Salto Santiago	4.1	0.82
Salto Osório	0.4	0.60
Passo Fundo	1.4	2.20
Passo Real	3.4	0.34
Jacuí	0.0	0.87
Itaúba	0.0	0.84
Dona Francisca	0.0	0.33
Governador P. Souza	0.2	6.58
Cubatão	1.4	5.71
Salto Grande	0.0	0.77
Aimorés	0.0	0.24

Table 1 - System Configuration / A - Hydroelectric Power Plants (Continued)

Power Plant	Useful Storage (km^3)	Average Efficiency ($MW/m^3/s$)
Mascarenhas	0.0	0.18
Três Marias	15.3	0.40
São Félix	34.2	1.13
Paraibuna/Paraitinga	2.6	0.62
Santa Branca	0.1	0.33
Jaguari	0.8	0.52
Funil	0.6	0.57
Ilha dos Pombos	0.0	0.26
Nilo Peçanha	0.0	2.64
Fontes	0.6	2.35
Pereira Passos	0.0	0.31

B - Thermoelectric Power Plants

Power Plant	Minimum Generation (MW)	Maximum Generation (MW)	Marginal Fuel Cost (US$/MWh)
Coal-Rio Grande do Sul (RS)	478	850	11.90
Nuclear	1 356	1 984	12.00
Coal-Santa Catarina (SC)	321	571	28.80
Coal-Southeastern Region (SE)	289	515	40.40

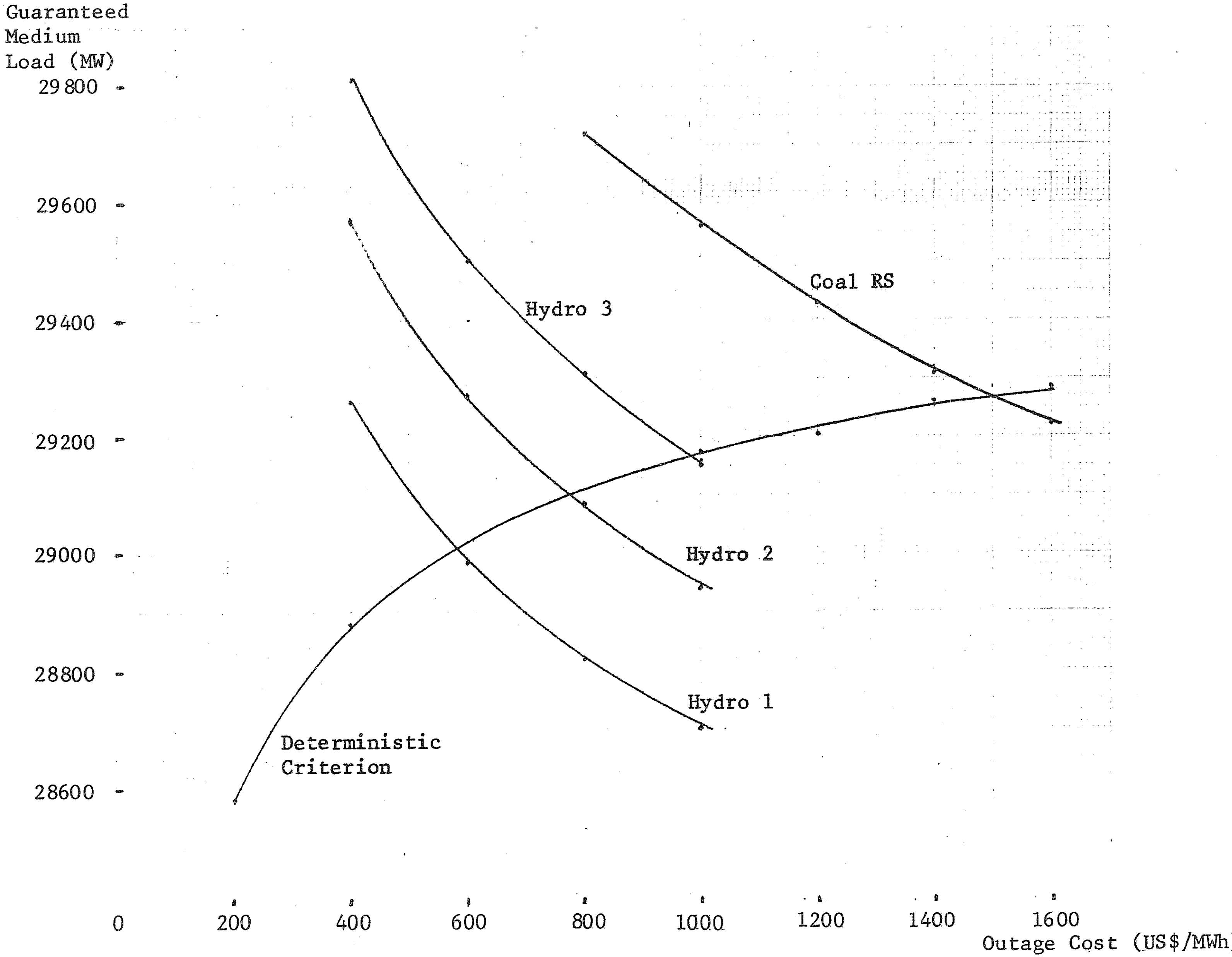

Figure 1 - Deterministic and Probabilistic Supply Criteria

AN ECONOMETRIC APPROACH TO PEAK LOAD FORECASTING

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I. Introduction

In an era of high energy costs and uncertainties associated with the expected growth of demand for electricity, load forecasting and capacity planning have become more important and more difficult.

A key aspect of any decision-making situation is being able to predict the circumstances which surround that decision and situation. The first and most critical step in long-range planning and evaluation of alternative planning strategies is the development of a reliable load forecast which seeks to predict, and explain changes in, the future demand for electricity. The purpose of this study is to forecast the summer and winter peak demand by using structural econometric models.

Two econometric equations for system peak demand were formulated: summer peak and winter peak. All variables in the models are in terms of their natural logarithms, and a pooled cross-section time series data base was employed.

The following sections will present the formulation and analysis of the summer and winter peak models and draw conclusions regarding some of the advantages and disadvantages of the econometric approach to peak load forecasting.

II. The Summer Peak Load Model

The first step in constructing an econometric model is to determine the important causative factors affecting the demand for electricity during peak periods. Therefore, a theory of the demand for electricity was developed.

In this study, the net system peak load demand by customers for electricity was found to be dependent upon the following social, economic and weather factors: personal income, the real price of electricity, the real price of natural gas, air conditioning saturation, cooling degrees, and number of residential customers.

Total Personal Income

Personal income has been used as a determinant of the economic climate because it is directly related to consumption, demand and production. As personal income increases, the consumption in the household sector (which includes expenditures in various commodities) and the production in the business sector are expected to increase. These factors will stimulate an increase in electricity consumption and net system peak load demand.

The Real Price of Electricity

The basic postulate of the theory of consumer behavior is that the consumer maximizes his utility (in the economic sense). Since his income is limited, he will react to price and income changes by changing his demands to satisfy his budget constraints. As the price of electricity increases, the price and income effects explain that the average consumer will consequently suffer a lower utility (in the economic sense) and therefore may conserve or substitute energy sources.

The Real Price of Natural Gas

As explained above, the consumer's reaction to price and income changes can be analyzed in terms of substitution and income effects. The effect of a given price change can be analytically decomposed into a substitution effect, which measures the rate at which he would substitute commodities for each other. As the price of natural gas increases, the average consumer will conserve or substitute energy sources.

Weather Conditions

The net system peak load is strongly related to the air conditioning load which is caused by the weather effect of the summer months. The weather effect was taken into consideration in the form of weighted average of cooling degree hours of the peak day and three previous days, air conditioning saturation, and number of residential customers. The total air conditioning variable incorporated in the model was calculated to take into consideration the saturation levels, unit tonnage sizes, and estimated unit EER. Model simulations could thereby be performed assuming different tonnage size, efficiency, or saturation scenarios.

Summer Peak Demand Equation

The summer peak demand equation is of the form:

$$Ln(SPK) = c + b_1 Ln(PI) + b_2 Ln(GASP) + b_3 Ln(ELECP) + b_4 Ln(WT) \qquad (1)$$

where:

SPK	=	net system summer peak load
PI	=	personal income in the service area
GASP	=	price index of natural gas
ELECP	=	price of electricity (typical residential and commercial electric bill)
ST	=	weather factor = AIR.COOL.RCUS
AIR	=	air conditioning saturation
COOL	=	weighted average of cooling degree hours of peak day and three previous days
RCUS	=	number of residential customers

All variables in the above model are in terms of their respective natural logarithms. This model specification produces constant elasticities for each variable. In fact, the coefficients themselves are the elasticities in a log-linear model.

Pooled cross-section time series data were collected and processed. The statistical model which describes the behavioral relationship between peak demand and the relevant causative variables was formulated by the use of ordinary least squares regression.

The estimation results of the summer peak model appear in Table 1. Inspection of the demand equation reveals a "good fit" of the data as evidenced by an R^2 of .987. The estimated income elasticity, electric price elasticity, natural gas price elasticity and weather variable are statistically significant and have the correct sign.

TABLE 1

Regression Results of the Summer Peak Load Model

Dependent Variable: LSPK

Right-Hand Variable	Estimated Coefficient	Standard Error	T-Statistic
C	-13.231	1.885	-7.017
LPI	.993	.155	6.400
LGASP	.213	$.526\text{x}10^{-1}$	4.065
LELECP	-.698	.227	-3.076
LWT	.109	$.200\text{x}10^{-1}$	5.459

R-Squared	=	.987
R-Bar-Squared	=	.984
Durbin-Watson Statistic	=	1.968
Number of Observation	=	28
Standard Error of the Regression	=	$.274\text{x}10^{-1}$

Forecast results are calculated by inserting into the econometric models the projected values of the driving variables. Naturally, there is great uncertainty associated with any set of input assumptions over a long period of time. Simulation and sensitivity tests are conducted and the most likely case is selected for planning purposes.

Following are the sources of projections associated with each of the independent variables:

- To estimate the future growth of air conditioning saturation, a logistic model was developed. The logistic curve is:

$$\mathrm{Ln}\left[\frac{\text{Air conditioning saturation}}{1 - \text{Air conditioning saturation}}\right] = C + \mathrm{Ln}\left(\begin{matrix}\text{real income}\\ \text{per capita}\end{matrix}\right) + \mathrm{Ln(time)}$$

- Residential customers were forecasted on a county-by-county basis and aggregated to create customer forecasts for the service area. Residential customers were found to be a function of population which was carefully studied by utilizing the Group Survival Analysis, the survival rates of each group of persons having shared characteristics (age/sex) during a certain period of time, and could be obtained from a statistical life analysis. The population of a certain group, i, could be estimated at time t as:

$$G_{it} = G_{i,t-1} \cdot s \pm M_{t-1,t} \tag{2}$$

$$B_{t-1,t} = r \cdot W_{t-1} \tag{3}$$

$$p = \sum_{t=1}^{n} G_{i,t} + B_{t-1,t} \tag{4}$$

where:

G_{it} = population of group i at time t
s = survival rate
M = migration
B = total number of births
r = birth rate
W = number of women in a certain group

- Personal income projections were obtained from the Wharton Econometric Forecasts.

- Natural gas price projections were obtained from a study of EPRI (Electric Power Research Institute).

III. The Winter Peak Model

Similar to the summer peak model, the winter net system peak load demand for electricity was found to depend upon the following social, economic and weather factors: personal income, the real price of electricity, the real price of natural gas, heating degree days, and number of residential, commercial and industrial customers with electric space heating. Since December is the month with Christmas lighting and the weather is usually less severe compared to January and February, a dummy variable was introduced to take these effects into consideration. All variables in the formulated model are in terms of their respective natural logarithms.

The winter peak demand equation is of the form:

$$\begin{aligned} \mathrm{Ln(WPK)} = c &+ b_1\mathrm{Ln(PI)} + b_2\mathrm{Ln(GASP)} + b_3\mathrm{Ln(ELECP)} \\ &+ b_4\mathrm{Ln(WTX)} + b_5\mathrm{(DEC)} \end{aligned} \tag{5}$$

where:

WPK	=	winter peak load
PI	=	personal income
GASP	=	price index of natural gas
ELECP	=	price of electricity (typical residential and commercial electric bill)
WTX	=	weather factor = (RSH + CISH) x HDD
RSH	=	number of residential customers with electric space heating
CISH	=	number of commercial and industrial customers with electric space heating
HDD	=	heating degree days of system peak day
DEC	=	dummy variable for month of December

The estimation results of the winter peak model appear in Table 2. Inspection of the demand equation reveals a "good fit" of the data, as evidenced by an R^2 of .987. The estimated income elasticity, electric price elasticity, natural gas price elasticity and the weather variable are statistically significant and have the correct sign.

TABLE 2

Regression Results of the Winter Peak Load Model

Dependent Variable: LWPK

Right-Hand Variable	Estimated Coefficient	Standard Error	T-Statistic
C	-3.083	1.191	-2.588
LPI	.489	$.966 \times 10^{-1}$	5.066
LGASP	.197	$.329 \times 10^{-1}$	5.999
LELECP	-.384	.145	-2.638
LWTX	$.775 \times 10^{-1}$	$.138 \times 10^{-1}$	5.620
DEC	$.700 \times 10^{-1}$	$.805 \times 10^{-2}$	8.694

R-Squared	=	.987
R-Bar-Squared	=	.984
Durbin-Watson Statistic	=	2.078
Number of Observation	=	42
Standard Error of the Regression	=	$.234 \times 10^{-1}$

IV. Conclusions

The main feature of the econometric modeling approach is that it attempts to explain electricity demand as a function of the major causal determinants and to quantify the behavioral relationships between each of the individual causative factors. The theoretical concept of the econometric model in peak load forecasting is that it quantifies and analyzes the decision making of electric consumers concerning electric usage based upon economic and weather factors. The advantage of the econometric approach over other methodologies is that it explains "why" and "how" rather than simply focusing on what actually happened. Therefore, econometric models provide insight into some of the underlying forces influencing the demand for electricity.

Another advantage of the econometric approach is its treatment of assumptions. The forecast results are calculated based on assumptions associated with the independent variables. As with all attempts to forecast future activity, the assumptions regarding future changes in economic condition or causal variables may be challenged and the impact on the forecast can be quantified if alternative assumptions are made.

Some of the limitations or problems generally associated with the econometric approach are data availability, multicolinearity, and the assumption that the same economic structure will exist in the future as has prevailed in the past. Given the element of uncertainty contained in any forecast, some deviation of the forecast from the ultimate reality is inevitable. However, if econometric models are carefully formulated, peak load can be forecasted within reasonable limits of accuracy.

A CASE STUDY OF USING THE CAPACITY EXPANSION AND RELIABILITY EVALUATION SYSTEM (CERES) PROGRAM TO CALCULATE THE AVOIDED COSTS OF CAPACITY FOR COGENERATORS AND SMALL POWER PRODUCERS

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The CERES (Capacity Expansion and Reliability Evaluation System) program was developed at The National Regulatory Research Institute to find the optimum capacity expansion plan for electric generating systems. However, the CERES program has other potential applications that would make the model useful in setting forward-looking rates. One such application would be the use of the CERES program to calculate the avoided cost of capacity, pursuant to the Public Utilities Policies Act (PURPA) Section 210, for purchases of power from cogenerators and small power producers that are qualifying facilities. In order to illustrate this potential application, the authors conducted a case study that calculated the avoided cost of capacity for cogenerators and small power producers for a major utility system, using both actual and hypothetical data gleamed from the utility's PURPA Section 133 filing. The data as to the amount of capacity available from cogenerators and the plant data for future additions to existing capacity were assumed.

In order to determine the avoided capacity costs, it is necessary to first determine a set of costs associated with the optimum capacity additions to existing generation capacity had there been no purchases from qualifying facilities. This is the reference case. To determine the reference case, the authors took the utility's load forecasts contained in Subpart D of their PURPA section 133. The authors used the utility's normalized load curve for 1982 as the reference year load profile. The normalized load characteristics for the utility were as follows: peak load of 7805 MW; energy demand of 40279 GWh; and a load factor of 58.9%.

The authors then updated the plant cost characteristics of the utility as reported in Subpart B of the utility's PURPA section 133 filing. To simplify the illustration, the plants were grouped together into 10 different plant codes. The generating system characteristics of these plants were as follows:

PLANT CODE	11	12	13	14	15
	SCHD	SCHD	SCHD	SCHD	SCHD
02 BASE CAPCTY MW	100.000	200.000	400.000	600.000	600.000
03 MAX CAPACITY MW	100.000	200.000	400.000	600.000	600.000
04 MAINT OTG DYS/YR	0.0	46.000	55.000	59.000	59.000
05 FORCED OTG.RATE	0.025	0.040	0.091	0.140	0.150
06 CAP. COST $/KW	0.0	0.0	0.0	0.0	0.0
07 BASE FL CST $/MWH	32.000	14.000	14.500	13.300	15.000
08 MAX FL CST $/MWH	32.000	14.000	14.500	13.300	15.000
09 ECONOMIC LIFE YR	35.000	35.000	35.000	35.000	35.000
10 FIX O.M.C.$/KW.YR	6.000	14.640	10.720	8.930	9.000
11 VAR O.M.C.$/MWH	450.000	0.500	0.700	0.600	1.000
12 SALVG VALUE K$	0.0	0.0	0.0	0.0	0.0
13 CAP. ESC. RATE	0.0	0.0	0.0	0.0	0.0
14 FUEL ESC. RATE	0.080	0.080	0.080	0.080	0.080

PLANT CODE	16	17	18	19	20
	SCHD	SCHD	SCHD	SCHD	SCHD
02 BASE CAPCTY MW	800.000	1000.000	200.000	600.000	400.000
03 MAX CAPACITY MW	800.000	1000.000	200.000	600.000	400.000
04 MAINT OTG DYS/YR	65.000	70.000	5.000	63.000	54.000
05 FORCED OTG.RATE	0.100	0.135	0.030	0.200	0.180
06 CAP. COST $/KW	0.0	0.0	0.0	0.0	0.0
07 BASE FL CST $/MWH	9.600	10.600	41.000	21.000	18.000
08 MAX FL CST $/MWH	9.600	10.600	41.000	21.000	18.000
09 ECONOMIC LIFE YR	35.000	35.000	35.000	35.000	35.000
10 FIX O.M.C.$/KW.YR	14.000	15.000	5.000	9.100	11.000
11 VAR O.M.C.$/MWH	0.500	0.800	470.000	1.400	1.600
12 SALVG VALUE K$	0.0	0.0	0.0	0.0	0.0
13 CAP. ESC. RATE	0.0	0.0	0.0	0.0	0.0
14 FUEL ESC. RATE	0.080	0.080	0.080	0.080	0.080

In running CERES the following input assumptions were made:
fuel escalation rate: 8%/year
user discount rate: 15%/year
reference case load growth rate: 4%/year
expansion candidates:

Plant ID	Fuel Type	Size (MW)	Construction Cost ($/kw)	Capital Cost Esc. rate	Economic Life (YR)
6	Coal	400	950	10%	35
3	Nuclear	800	1550	10%	35
5	Coal	600	1150	10%	35
9	Oil	100	400	10%	35

planning horizon: 20 years

The outcome of the first run of the computer simulation of capacity planning determined a set of costs associated with the optimum addition to existing generation capacity had there been no qualifying facility. The characteristics of the optimal expansion plan obtained from CERES are shown in table 1. Thus the characteristics of reference case optimum expansion plan yielded the following:

$$\Sigma C_t = 7931.312 \times \$10^6$$

$$\Sigma O_t = 8730.664 \times \$10^6$$

$$\Sigma R_t = 1444.664 \times \$10^6$$

where t is an index for the n years in the utility's planning horizon; C_t is the total cost for units that enter service in year t; R_t is the cost of units entering service in year t that is not recovered over the planning horizon.

$$\Sigma(C_t - R_t + O_t) = 15217.312 \times \$10^6$$

$$\Sigma K_t = 400 \times 7 + 800 \times 6 + 600 \times 2 = 8800 \text{ MW}$$

Next the authors assumed that the utility purchased, on a firm commitment basis from industrial cogenerators, 100 MW of capacity uniformly across each day, week, and year for a period of 10 years beginning 1985. Thus, the load impact of the power purchased from cogenerators is a 100 MW peak load reduction, and an 876 GWh/yr energy reduction. The authors then adjusted the normalized load profiles of the reference case to account for the power purchased from cogenerators, as shown in the figure below.

TABLE 1: REFERENCE CASE RESULTS

CHARACTERISTICS OF THE OPTIMAL OR SUBOPTIMAL SOLUTION

	PLANT TYPE					UNSERVED	TOTAL			
YEAR	6	3	5	9	LOLP+	ENERGY (MWH)	OPERATING COST*	CAPITAL COST**	SALVAGE VALUE*	OBJECTIVE FUNCTION*
1983	0	0	0	0	0.000052	0.83360E+04	654.197	0.0	0.0	654.196
1984	0	2	0	0	0.000007	0.16896E+05	529.811	2269.033	83.817	3369.222
1985	0	2	0	0	0.000018	0.15136E+05	529.422	0.0	0.0	3898.642
1986	0	3	0	0	0.000011	0.30032E+05	480.657	1038.006	57.048	5360.254
1987	0	3	0	0	0.000029	0.29296E+05	482.635	0.0	0.0	5842.887
1988	0	4	0	0	0.000019	0.45872E+05	440.321	949.706	76.698	7156.207
1989	0	4	0	0	0.000048	0.45520E+05	444.906	0.0	0.0	7601.109
1990	0	5	0	0	0.000034	0.57024E+05	407.725	868.917	102.085	8775.660
1991	0	5	0	0	0.000082	0.58384E+05	415.176	0.0	0.0	9190.832
1992	0	6	0	0	0.000063	0.65776E+05	382.110	795.001	134.752	10233.187
1993	0	6	0	0	0.000146	0.76880E+05	392.716	0.0	0.0	10625.902
1994	1	6	0	0	0.000194	0.81168E+05	395.828	222.904	54.131	11190.496
1995	2	6	0	0	0.000261	0.88784E+05	397.827	213.213	61.834	11739.695
1996	4	6	0	0	0.000217	0.79232E+05	387.338	407.885	141.072	12393.840
1997	5	6	0	0	0.000306	0.94736E+05	390.449	195.075	80.361	12898.996
1998	6	6	0	0	0.000438	0.11667E+06	394.713	186.594	91.445	13388.852
1999	7	6	0	0	0.000631	0.14664E+06	399.979	178.481	103.942	13863.363
2000	7	6	1	0	0.000723	0.16272E+06	396.769	309.993	214.308	14355.812
2001	7	6	2	0	0.000848	0.18787E+06	392.588	296.514	243.105	14801.805
2002	7	6	2	0	0.001893	0.32344E+06	415.511	0.0	0.0	15217.312

\+ ZERO MEANS LOLP VALUE SMALLER THAN 0.000001

* MILLIONS OF 1982 DOLLARS

** PLANT COSTS ARE GIVEN AS THE TOTAL WORTH OF THE PLANT AS IT COMES ON LINE. IF THE FIXED CHARGE RATE OPTION IS USED, CAPITAL COSTS REPRESENT THE FIXED CHARGES FOR EACH PLANT.

Source: Printout of CERES program.

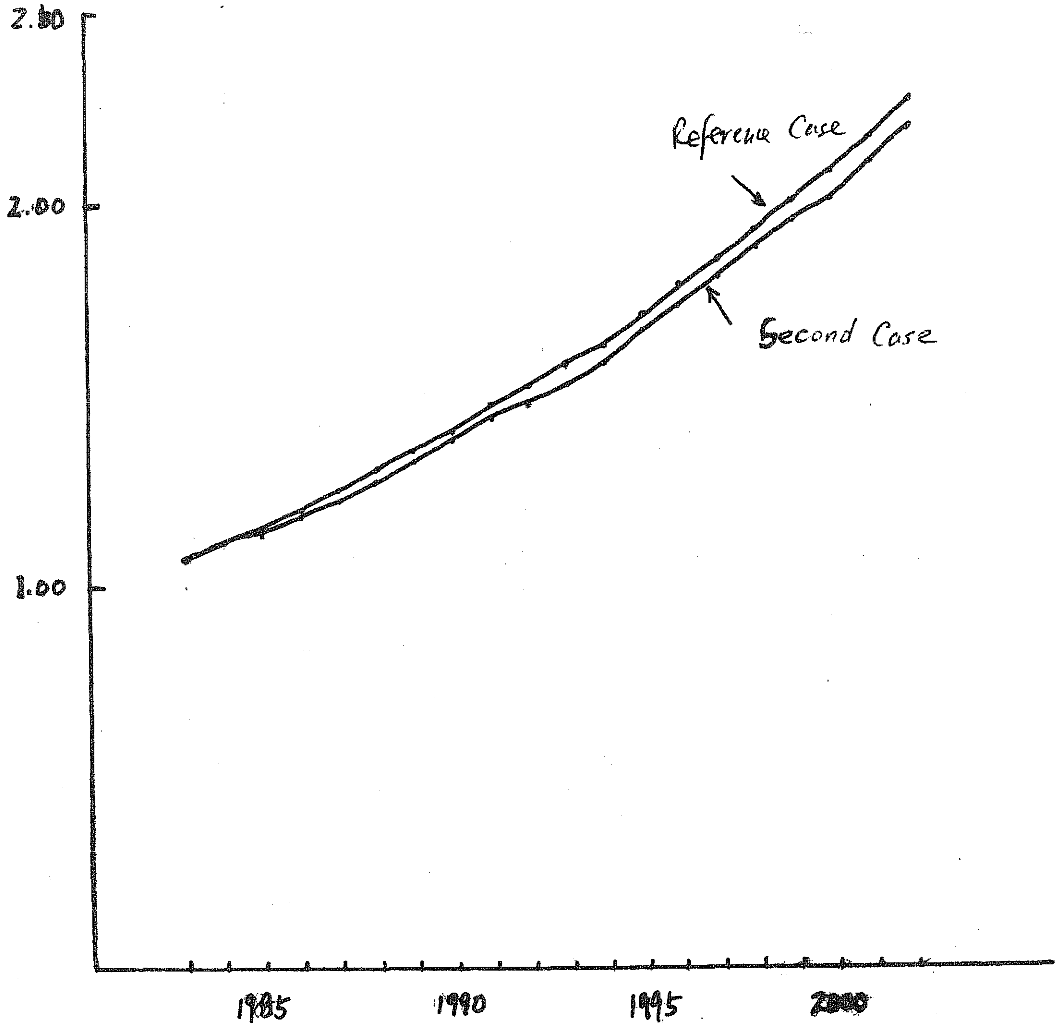

Figure 1: Cumulative Growth

Using this set of future loads, CERES was run to obtain the optimum expansion plan associated with this second case, the characteristics of which are shown in table 2. Thus the characteristics of the second case yielded the following:

$\Sigma C'_t = 7440.452 \times \$10^6$

$\Sigma R'_t = 1374.961 \times \$10^6$

$\Sigma O'_t = 8622.168 \times \$10^6$

TABLE 2: SECOND CASE RESULTS

CHARACTERISTICS OF THE OPTIMAL OR SUBOPTIMAL SOLUTION

	PLANT TYPE					UNSERVED ENERGY	TOTAL OPERATING	CAPITAL	SALVAGE	OBJECTIVE
YEAR	6	3	5	9	LOLP+	(MWH)	COST*	COST**	VALUE*	FUNCTION*
1983	0	0	0	0	0.000052	0.83360E+04	654.197	0.0	0.0	654.196
1984	0	2	0	0	0.000007	0.16896E+05	529.811	2269.033	83.817	3369.222
1985	0	2	0	0	0.000011	0.15632E+05	513.282	0.0	0.0	3882.503
1986	0	2	0	0	0.000029	0.15536E+05	515.230	0.0	0.0	4397.730
1987	0	3	0	0	0.000019	0.28224E+05	466.810	992.875	66.239	5791.172
1988	0	3	0	0	0.000046	0.31216E+05	471.145	0.0	0.0	6262.312
1989	0	4	0	0	0.000031	0.45232E+05	428.901	908.414	88.586	7511.035
1990	0	4	0	0	0.000074	0.47120E+05	435.901	0.0	0.0	7946.934
1991	0	5	0	0	0.000054	0.56912E+05	398.651	831.138	117.397	9059.320
1992	0	5	0	0	0.000084	0.58496E+05	390.676	0.0	0.0	9449.992
1993	0	6	0	0	0.000064	0.65968E+05	359.554	760.435	154.403	10415.570
1994	0	6	0	0	0.000149	0.77216E+05	369.625	0.0	0.0	10785.191
1995	1	6	0	0	0.000261	0.90400E+05	386.105	213.213	61.834	11322.668
1996	3	6	0	0	0.000212	0.79968E+05	374.862	407.885	141.072	11964.336
1997	4	6	0	0	0.000294	0.91280E+05	377.585	195.075	80.361	12456.629
1998	5	6	0	0	0.000414	0.11190E+06	381.329	186.594	91.445	12933.102
1999	6	6	0	0	0.000590	0.13942E+06	386.137	178.481	103.942	13393.770
2000	7	6	0	0	0.000849	0.17699E+06	391.939	170.721	118.025	13838.398
2001	9	6	0	0	0.000894	0.17603E+06	383.736	326.596	267.768	14280.957
2002	9	6	0	0	0.001795	0.30365E+06	406.707	0.0	0.0	14687.660

+ ZERO MEANS LOLP VALUE SMALLER THAN 0.000001

* MILLIONS OF 1982 DOLLARS

** PLANT COSTS ARE GIVEN AS THE TOTAL WORTH OF THE PLANT AS IT COMES ON LINE. IF THE FIXED CHARGE RATE OPTION IS USED, CAPITAL COSTS REPRESENT THE FIXED CHARGES FOR EACH PLANT.

Source: Printout of CERES program.

$$\Sigma(C_t' - R_t' + O_t') = 14687.66 \times \$10^6$$

$$\Sigma K_t' = 400 \times 9 + 800 \times 6 = 8400 \text{ MW}$$

By running two CERES expansion simulations, the authors were thus able to determine the type, the amount, and the cost of capacity that is avoided by a utility which is purchasing power from qualifying facilities. Using the results of the reference case and the second case, the authors then calculated the cost of avoided capacity over the entire planning horizon by finding the difference between the total costs of each case. ACC in equation (1) is the cost of avoided capacity.

$$ACC = \frac{\Sigma(C_t - R_t + O_t) - \Sigma(C_t' - R_t' + O_t')}{\Sigma(K_t - K_t')} \qquad \text{Eq. (1)}$$

$$= \frac{15217.312 - 14687.66}{8800 - 8400}$$

$$= \frac{529.652}{400}$$

$$= 1.324 \times (\$10^6/\text{MW})$$

The reoptimization of the utility's system and adjustments to construction plans will also change the utility's tax liability. Because this change in the tax liability is capacity-related, it should properly be included in the cost of avoided capacity. The algorithm for the avoided taxes per unit of avoided capacity is shown in equation (2). In equation (2), α is the portion of the utility's net operating revenues paid to holders of preferred and common stock, including retained earnings; t_x^I is the combined federal, state, and local tax rate; and t_x^P is the property tax rate. For our illustrative application:

(assuming $\alpha = 40\%$, $t_x^I = 60\%$, $r = 13.5\%$, $t_x^P = 5\%$)

$$ATX = \frac{\dfrac{\alpha t_x^I \, \Sigma(C_t - C_t')\, r}{(1-t_x^I)} + t_x^P \, \Sigma(C_t - C_t')}{\Sigma(K_t - K_t')} \qquad \text{Eq. (2)}$$

$$= \frac{\dfrac{(0.4)(0.6)(7931.321-7440.453)(0.135)}{(1-0.6)} + (0.05)(7931.321-7440.453)}{8800-8400}$$

$$= \frac{39760 + 24.543}{400}$$

$$= 0.161 \qquad (10^6\$/\text{MW})$$

Finally, the cost of avoided capacity must be annualized in order to arrive at a monthly $/KW charge for capacity to a firm cogenerator. These costs consist of the annual cost necessary to pay interest and dividends on securities issued to construct additional generating capacity plus the straight-line depreciation charge associated with the avoided capacity plus the avoided taxes. In order to calculate the annual cost of avoided capacity, AAC, equation (3) is used.

$$AAC = ACC + \frac{\Sigma(R_t - R_t')}{(K_t - K_t')} r + \frac{ACC}{n} + ATX \qquad \text{Eq. (3)}$$

$$= 1.324 + \frac{(1444.664-1374.961)}{(8800-8400)} (0.135) + \frac{1.324}{20} + 0.161$$

$$= 0.202 + 0.066 + 0.161$$

$$= 0.429 \qquad (10^6 \$/MW/YR)$$

$$= 429 \qquad (\$/KW/YR)$$

$$= 35.75 \qquad (\$/KW/Month)$$

In equation (3), r is the utility's weighted average cost of capital.

Using the results of the two optimum capacity expansion plans, the authors found that the monthly charge for avoided capacity was $35.75 per kw of capacity. As shown in figure 2, the purchases of power from qualifying facilities resulted in the one-year deferral of three 800 MW nuclear base load units during the period from 1986 to 1993, and the replacement of two 600 MW coal base load units with two 400 MW coal units.

While the results of this case study may seem a bit high to some, the case study results are not unreasonable. The case study demonstrates that a utility can avoid substantial capacity costs by reoptimizing its capacity expansion plans to account for a lower future load due to the addition of cogenerators. The savings that can be realized from these sales can be readily translated into avoided cost based rates that fully promote the development of economically justifiable cogeneration and small power production.

As the results of the case study are not unreasonable, the authors conclude that an optimum capacity expansion planning model, such as CERES, can be utilized as a first step in calculating the avoided cost of capacity due to the addition of cogenerators and small power producers.

Year	6 (C-400) Ref	6 (C-400) 2nd	3 (N-800) Ref	3 (N-800) 2nd	5 (C-600) Ref	5 (C-600) 2nd	9 (O-100) Ref	9 (O-100) 2nd
	Annual Addition							
1983	0	0	0	0	0	0	0	0
1984	0	0	2	2	0	0	0	0
1985	0	0	0	0	0	0	0	0
1986	0	0	1	0	0	0	0	0
1987	0	0	0	1	0	0	0	0
1988	0	0	1	0	0	0	0	0
1989	0	0	0	1	0	0	0	0
1990	0	0	1	0	0	0	0	0
1991	0	0	0	1	0	0	0	0
1992	0	0	1	0	0	0	0	0
1993	0	0	0	1	0	0	0	0
1994	1	0	0	0	0	0	0	0
1995	1	1	0	0	0	0	0	0
1996	2	2	0	0	0	0	0	0
1997	1	1	0	0	0	0	0	0
1998	1	1	0	0	0	0	0	0
1999	1	1	0	0	0	0	0	0
2000	0	1	0	0	1	0	0	0
2001	0	2	0	0	1	0	0	0
2002	0	0	0	0	0	0	0	0
Total	7	9	6	6	2	0	0	0

Figure 2: A Comparison of the Optimum Capacity Expansion Plans for the Reference and the Second Cases.

LOAD AND ENERGY FORECASTING METHODS AND PRACTICES IN EGYPT

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1. REVIEW OF FORECASTING METHODS

The methods used for electrical load and energy forecasts fall within five main categories namely:

- Accumulative methods,
- Extrapolation methods,
- Sentiment methods,
- Correlation between the national economy and energy demand methods, and
- Multiple regression methods.

All these methods are briefly discussed hereafter.

1.1 The Accumulative Methods

The individual future demands for electrical energy (end use) of the various sectors of the country's economy are estimated. These separate estimates are then added in order to give a complete forecast for the country. Whether the estimated demand of each sector is based on the evaluation of the needs of a specific preplanned projects or on the extrapolation of the demand of this specific sector (end use), the forecast of the total demand is only reliable for short term. The various versions of the accumulative forecast method normally fails to account (correctly) for the diversity of peak loads in an accurate manner and thus tends to yield an overestimation of the overall peak load.

1.2 The Extrapolation Methods

The average growth rate of the demand over the past years is determined. A factor is applied to the historical growth rate and this modified growth rate is assumed for the future. The confidence in the predicted values is usually impaired if the historical growth has assumed a particularly irregular rate. It is also not easy to determine the modifying to be used for a particular country at a particular stage of its development.

1.3 The Sentiment Methods

These involve basing the forecast for a particular country upon either the forecast for what is believed to be closely comparable country, or upon the recent experience of a country to be similar but rather more developed.

Clearly the accuracy of these methods is completely dependent upon the judgment of how comparable the reference country (or countries) really is.

1.4 The Correlation between the National Economy and Energy Demand Methods

A relation is established between the energy demand and some measure of the national economy either for the country under study or on a world wide basis. This relation showed to be more regular if the per capita values are used. In the presence of a sufficiently reliable forecast for the development of the national economy (GNP) during certain period, the established relation can be used to predict the energy demand during the same period. Irrespective of how attractive the logic on which these methods may seem, it should be clear that any uncertainty in the forecast for national economy (GNP) during the study period will be amplified to the energy demand forecast.

However, when a relationship between electricity consumption and national product has been established, a forecast of nation product is then required. In times of stable economic growth statistical techniques are used to extend historic trends into the future, or to apply relationships between national product and some independent variables for which predictions have been made. In times of uncertainty judgemental and subjective techniques have to be relied on. One of these techniques is the Delphi method which is used to establish the probability of various rates of economic growth. Delphi is a structured method of sampling expert opinion about the timing and probability of future events. The technique involves the circulation of a questionnaire to each of a panel experts who are asked to give their subjective forecasts and then return the form. The questionaire is sent a number of times to the panel, the results for each being fed back to the respondents.

1.5 The Multiple Regression Methods

The demand function of electricity does not depend only on the national economy, but also on several independent variables such as electricity rates, strategy of energy conservation and load management, saturation of electricity usage,...etc. The demand function may be simplified to multiple regression equation of the form:

$$Y = a + b_1 X_1 + b_2 X_2$$

where X_1 and X_2 are the independent variables; and a, b_1 and b_2 are the regression coefficients. The significance of the model is statistically tested using one of the significance tests.

2. APPLICATION OF THE DIFFERENT LOAD FORECAST METHODS TO EGYPT'S NATIONAL UNIFIED POWER SYSTEM (NUPS)

The historical growth of peak load and total energy consumed/annum for the preceding two decades show clearly the difficulty to obtain a long term forecast with reasonable accuracy.

The regularity of growth rate appears from the straight line relation between the variable under study and time when plotted on a semi-logarthmic scale. As a result of such a plot the growth of the peak load and energy demand was highly irregular during the past 25 years, due to the prevailing war in the Middle East particularly in 1956, 1967 and 1973 and their economic after effects.

It was difficult to choose one method for Egypt and, therefore, most of the above-mentioned methods were attempted. The results are briefly discussed, hereafter, and a recommended method is explained.

(i) The accumulative methods yielded a specially exaggerated future values.

(ii) The direct extrapolation method is more suitable for a country with stable pattern of growth and it cannot readily be recommended for Egypt. Since it was expected, now is a proven fact, that the rates of growth of peak load and energy demands are becoming very high indeed to compensate for low erratic previous growth rates during the war years till 1974. Also higher growth rates are attributed to the new changes in the country's economic policy by increasing private business activities and encouraging foreign capital. However, the government-owned public sector, still controls large industrial enterprises and regulate them.

(iii) The sentiment methods were difficult to apply and this difficulty lies in choosing a country at a comparable development state or slightly advanced to use its growth rates in evaluating the peak load and energy demand. However, for developed industrialized countries the load doubles every (10-12) years, while for the developing countries it doubles every (7-8) years. Although in Egypt the peak load has almost doubled in the last 5 years.

(iv) The correlation between the national economy and the energy demand was applied by H. Aoki in his forecast given in the Market Survey Report for IAEA, September 1973. As mentioned before the uncertainty in the values estimated for GNP per capita per annum used in the energy forecast would throw the whole process in doubt and renders it not any better than utilizing the peak demand directly in the forecast.

(v) The multiple regression method gives more reliable forecasts, but it needs to apply sophisticated mathematical models and excessive computer runs especially if the independent variables are more than two.

3. MAXIMUM DEMAND FORECAST BY SUPERIMPOSING METHOD

Time series analysis of monthly or quarterly peak loads is considered one of the best and common techniques used for long-term peak demand of a power system in a well-developed country.

However, experience gained in load forecasting for Egypt over the past 20 years, showed that the best recommended method to suit local conditions is to obtain the natural growth rate of the pattern of the society over a large number of years and this should be superimposed on the industrialization plan. The reason that the ordinary time series analysis cannot be applied to developing countries like Egypt is attributed mainly to the planned heavy industrial loads which have a large contribution in the total requirements of the country of the energy or peak load demand.

The superimposing method of a regression model in conjunction with the heavy industrial load is used to forecast the annual peak demand.

3.1 General Approach

In the long-range forecast it is necessary to consider some basic assumptions:

(i) The large loads are excluded from the historical data. The order of size of excluded loads is considered relative to the system load and can be taken as e.g. 10% of the total power system load.

(ii) There will be no extreme fluctuations in economic activities; although there may be booms or recessions.

The historical data of the power system is prepared by excluding the heavy industrial loads from the monthly peak demand. The growth of this part of demand is called the Society Natural Growth. Applying then the time-series analysis to forecast the natural growth of the monthly peak demand. The planned heavy industrial loads are added to the predicted natural growth loads. The coincidence of loads and the losses in the transmission system should be also considered to calculate the total peak demand of the power system. The deviations of the predicted monthly peak demand from the expected values are considered by assuming that these deviations follow the statistical student's "t" distribution.

3.2 Time-Series Analysis

The time-series analysis is the technique of making inference about the future on the basis of what has happened in the past. If a series has shown some trend in its variations for a long period of time in the past, it can be assumed that such trend will continue in the future and that continuity is the basis of the forecasting. The used model is chosen to be in the form:

$$YL(X) = TR(X) \times SK \tag{1}$$

where

- YL is the monthly peak load
- TR is the trend function
- SK is the seasonal monthly index of the K th month
- X is the interval of time-series-month

The seasonal monthly indices SK are calculated from the 12-month moving-averages.

The selected trend function is the exponent function:

$$TR(X) = \exp(R) \tag{2}$$

$$R = \overline{YL} - B(X-\overline{X}) \tag{3}$$

where $\overline{YL}$ and $\overline{X}$ are the mean of YL and X, respectively.

The parameter B recognize the least-square of errors, given by:

$$B = \frac{\sum_{i=1}^{n} (X_i-\overline{X})\ (Y_i-\overline{Y})}{\sum_{i=1}^{n} (X_i-\overline{X})^2} \tag{4}$$

The upper and lower limits of the monthly peak demand forecast are calculated from the equations:

$$TR_{max}(X) = \exp(t_{\alpha,N}E_X+R)\ S_{Kmax} \tag{5}$$

$$TR_{min}(X) = \exp(T_{i-\alpha,N}E_X+R)\ S_{Kmin} \tag{6}$$

where

$$E_X = S_{YX}\ (1+1/N + (X-\overline{X})^2 \ / \sum_{X=1}^{N} (X-\overline{X})^{\frac{1}{2}}) \tag{6}$$

and

E_X^2 Variance of load at month X

S_{xY} is the standard deviation of Y and X

$t_{\alpha,N}$ are the tabulated values corresponding to the student's "t" distribution with N degree

$t_{1-\alpha,N}$ of freedom, and α level of confidence

N is the number of observations (months

S_{Kmax} is the maximum value of S_K

S_{Kmin} is the minimum value of S_K

4. CONCLUSIONS

The superimpose method was used to forecast the annual peak demand of the National Unified Power System of Egypt from the monthly historical data. The method is applied to the past years of the historical data, and the error in prediction did not exceed 3.7% where the average of error was 1.9%. The coincidence factor between the planned heavy loads and the natural growth load is taken to be 0.98. The total losses on the high voltage transmission and distribution networks are assumed 7%. Tables from (1) to (3) show the forecast of the maximum demand, energy and load factor of the Egyptian National Power System for the most expected case, upper limit and lower limit respectively.

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Table (1)

Egyptian National Unified Power System

Load and Energy Forecast

Most Expected Case (Median)

Year	Maximum Demand MW		Energy TWH		Load Factor
	Forecast	Actual	Forecast	Actual	
1979	2828	2838	16.364	16.928	0.683
1980	3239	3180	18.375	19.059	0.684
1981	3512	3553	20.979	20.748	0.682
1982	3848	3900	22.836	23.353	0.676
1983	4225		24.961		0.647
1984	4648		27.428		0.673
1985	5120		30.017		0.669
1986	5649		33.000		0.665
1987	6241		36.346		0.665
1988	6905		40.190		0.663
1989	7646		44.279		0.661
1990	8477		48.968		0.659
1991	9100		52.491		0.658
1992	9774		56.432		0.657
1993	10500		60.394		0.656
1994	11287		64.835		0.656
1995	12135		69.624		0.655
1996	13052		74.990		0.655
1997	14040		80.382		0.654
1998	15110		86.420		0.653
1999	16264		92.933		0.652
2000	17512		100.238		0.652
2005	26000		148.000		0.650

Table (2)

Egyptian National Unified Power System
Load and Energy Forecast
(Upper Limit)

Year	Maximum Demand	Energy TWH	Load Factor
1979	3140	18.690	0.68
1980	3530	21.030	0.68
1981	3910	23.170	0.68
1982	4300	25.380	0.68
1983	4740	27.860	0.68
1984	5240	30.730	0.67
1985	5790	33.800	0.67
1986	6420	37.330	0.66
1987	7120	41.310	0.66
1988	7910	45.890	0.66
1989	8800	50.800	0.66
1990	9800	56.450	0.66
1991	10530	60.570	0.66
1992	11320	65.190	0.66
1993	12170	69.830	0.65
1994	13090	75.020	0.65
1995	14080	80.620	0.65
1996	15160	86.900	0.65
1997	16310	93.210	0.65
1998	17560	100.270	0.65
1999	18910	107.890	0.65
2000	20370	116.440	0.65
2005	29000	165.000	0.65

Table (3)
Egyptian National Unified Power System
Load and Energy Forecast
(Lower Limit)

Year	Maximum Demand MW	Energy TWH	Load Factor
1978	2300	13.910	0.69
1979	2540	15.310	0.69
1980	2850	17.150	0.69
1981	3140	18.820	0.69
1982	3420	20.230	0.68
1983	3740	22.230	0.68
1984	4100	24.290	0.68
1985	4490	26.480	0.67
1986	4930	28.960	0.67
1987	5430	31.750	0.67
1988	5980	34.930	0.67
1989	6590	38.290	0.66
1990	7270	42.190	0.66
1991	7790	45.110	0.66
1992	8360	48.440	0.66
1993	8980	51.790	0.66
1994	9640	55.540	0.66
1995	10360	59.590	0.66
1996	11130	64.110	0.66
1997	11970	68.680	0.66
1998	12870	73.770	0.65
1999	13850	79.280	0.65
2000	14900	85.450	0.65
2005	21000	120.000	0.65

THE UTILIZATION OF DFI-GEMS AND WASP MODELS FOR ELECTRIC LOAD FORECASTING AND OPTIMIZATION OF GENERATING CAPACITY EXPANSION, WITHIN THE SCOPE OF THE NATIONAL ENERGY PLAN FOR PORTUGAL

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1. Introduction

The National Energy Plan (PEN), completed in October 1982, was the first long term one prepared for the energy sector, up to this date, in Portugal.

Its main purpose was to equate wholly the Country energy problems, integrated in the world available prospects, for an extended temporal horizon, so as to allow to quantify energy purposes and to determine an energy policy and medium term investment programs.

The specific characteristics of the energy sector, with the long period of elaboration of the new facilities -from their study and design up to their commissioning- impose the adoption of a sufficiently remote planning horizon; however, changes that are expected in the field of energy for the first decades of the next century are of such importance that they make the analysis covering a period longer than 30 years highly unrealistic. Bearing in mind these conditionings, it was thought correct and safe to adopt as the period to study in the PEN that up to 2010; 1980 was taken as a base year, and all the calculations were made with constant prices of that year.

Work for preparing the PEN, which was carried out by an Executive Group composed by specialists from General Directorate for Energy and other government departments, and from Energy Sector Public Enterprises, supervised by the Plan Committee, presided over by the Secretary of State for Energy, occurred between June 1981 and October 1982, and was the result of the development and further examination of former studies, namely those performed within the scope of the "Portugal-USA Cooperative Energy Assessment", completed in 1981.

2. Methodology

The methodology adopted for the elaboration of the PEN can be very summarily described, as follows (see Figure 1):

I - Characterization of two economic and social development scenarios for Portugal during the period 1980-2010, fitted in scenarios of the world economy evolution, and labeled as:

Scenario A - "Development and integration of the portuguese economy". This scenario presumes an average growth in GDP of 5.9% per year over the planning period.

Scenario B- "Slow development and partial integration of the portuguese economy", that assumes a more modest GDP growth rate - 4.1% per year in the period 1980-2010.

II- Characterization of some hypothesis of evolution, at a world level, of primary energies real prices (oil, natural gas, coal, uranium).

III- By applying the MEDEE model, developed at the Institut Économique et Juridique de l'Énergie de Grenoble (France), the projection of useful energy demand was made (Scenarios of Energy Demand) to the large sectors of national economy -residential, services, industry, agriculture / fishing, transportation- for every scenario defined under I, throughout the period under study (1980-2010).

Figure 2 shows, for the scenarios A and B, the useful energy demand projections, by sector of activity.

IV - For every scenario of energy demand and for several hypothesis of evolution of the prices of primary energy, of the intensity of energy conservation, of the discount rate and of evolution of the equipment prices, model DFI - Generalized Equilibrium Modelling System (GEMS), developed by Decision Focus Incorporated of Palo Alto, California (USA), was employed for determining the optimal expansion of the Portuguese energy system. This model, which is based on the general economic equilibrium theory, provides data on the way several conversion, transport, distribution and utilization of energy technologies, will compete for meeting the demand for useful energy in every sector mentioned under III, taking into account individual preferencies, the predictable degree of future evolution, conditionings of a technological kind and the purpose of minimizing whole costs related to the energy system. The structure of the energy network is considered to be a fundamental assumption of the analysis. All present and potential activities associated with the production and provision of energy resources, conversion of the resources into fuels, transport, distribution and utilization of the fuels in the end-use sectors of the economy, must be included in the network. A schematic diagram of the network is shown in Fig.3 and a detailed version of the Public electric subsector network is illustrated in Fig.4. The main results of DFI-GEMS model concern:

- the evolution of the sharing of the different forms of primary and secondary energy for meeting demand;
- the projections of the energy prices in every link of the network that represents the energy system.

Figure 5 shows the final energy consumption by energy forms - total delivered fuels - for the scenarios A and B, during the study period. In Figure 6 we can see the corresponding projections of the primary energies mix.

From the several simulations carried out with the DFI - GEMS model, and after detailed analysis of the respective results, the characterization of two scenarios of evolution of the demand for electric power was obtained, throughout the period under study, basically associated to the scenarios of economic development referred to under I, and, therefore, mentioned also here as scenarios A and B.

V - For every main energy subsector -oil, coal, natural gas, uranium, renewable energies and electric subsector- a more complete and detailed analysis was then carried out aiming at the characterization of the respective long term development plans (1980-2010) and medium term investment programs (corresponding to the period that will elapse up to 1990).

The expansion of the Public electric subsector to meet the demand in the scenarios A and B, specified under IV, was optimized with the WASP model -Wien Automatic System Planning Package- of the International Atomic Energy Agency (under the WASP-II version). Starting from this model results, and after their confirmation with a simulation program developed by Electricidade de Portugal -VALORÁGUA model- which deals in more detail with the hydroelectric component, the development programs of the electric subsector were established, for the period 1980-2010, for every demand scenario already referred to.

VI - Finally, the analysis was also carried out, as far as possible, of the overall economical effects, direct and indirect, of the future energy demand, namely its impact on the evolution of the balance of payments and in the aggregate levels of gross fixed capital formation (GFCF), throughout the period under study.

3. Electric Power System expansion - Main results

3.1 Scenarios of evolution of the electric power demand.

As stated under 2.IV we derived these growth scenarios from DFI-GEMS model results. TABLE I shows the annual average rate of growth of electric power demand, established for scenarios A and B, for each decade of the study period.

3.2 Optimal programs for the generating capacity expansion.

These optimal expansion programs were established by the WASP model for each demand scenario, as stated in 2.V. In what concerns the installed capacity by plant type, its evolution over the study period is shown, for scenarios A and B, in TABLE II.

Figures 7 and 8 show, respectively, the installed capacity and the annual generation -in average hidrological condition-, for selected years during the study period.

To finish this brief presentation of the main results obtained for the optimal expansion of the Public electric subsector, we illustrate, in Figure 9, the structure of the energy sector investment program , for the present decade; as we can see, about 70% of this capital expenditure will be allocated to electric subsector. This fact strongly emphasizes how important is correct planning and program implementation in the electric subsector, when we want to optimize the allocation of scarce capital resources in the energy sector.

TABLE I

Electric Power Demand

Average Growth Rate

PERIOD	SCENARIO A	SCENARIO B
1980-1990	6.79%	4.92%
1990-2000	5.16%	3.58%
2000-2010	5.21%	3.70%

TABLE II

Installed Capacity by Plant Type

Scenarios A and B

(MW)

YEAR	HYDROELECTRIC				THERMAL				TOTAL	
	NORMAL		REVERSIBLE		FOSSIL-FUELLED		NUCLEAR			
	A	B	A	B	A	B	A	B	A	B
1980	2196	2196	72	72	1632	1632	-	-	3900	3900
1990	3147	3147	776	776	4095	3495	-	-	8018	7418
2000	3752	3854	2028	1158	4381	3181	3800	1900	13961	10093
2010	4489	4874	3378	1618	3150	1950	10450	5700	21467	14142

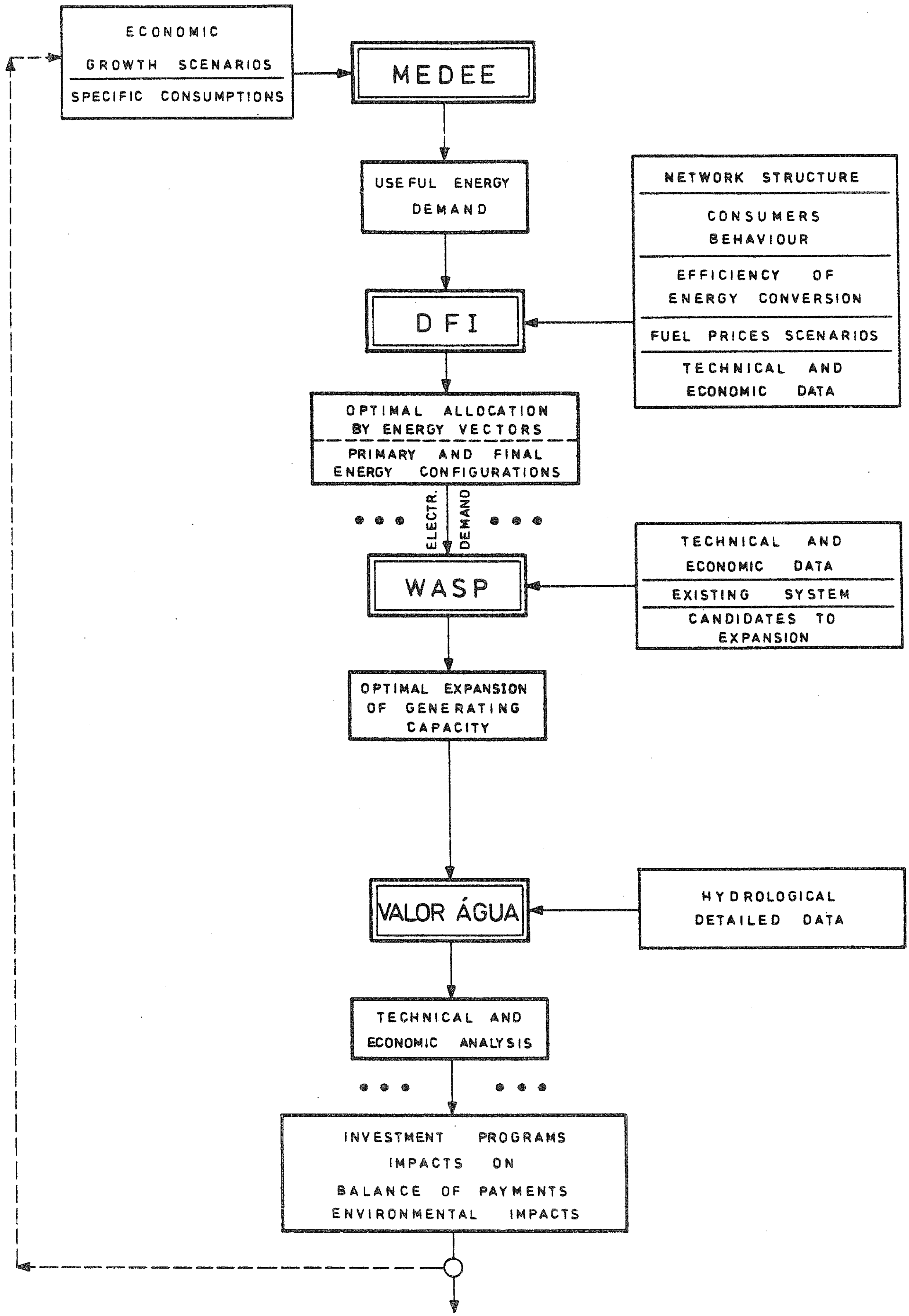


FIG. 1 METHODOLOGY – SCHEMATIC DIAGRAM

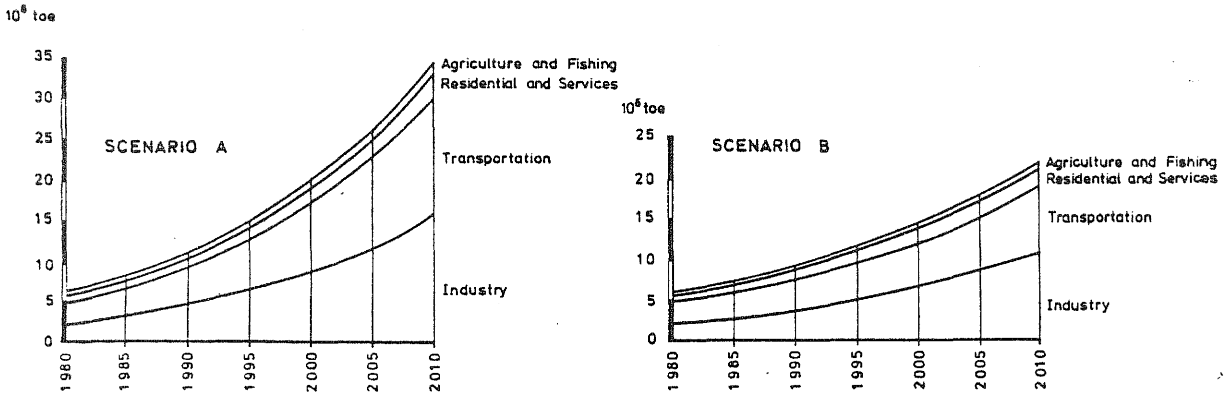


FIG. 2 — USEFUL ENERGY DEMAND PROJECTIONS

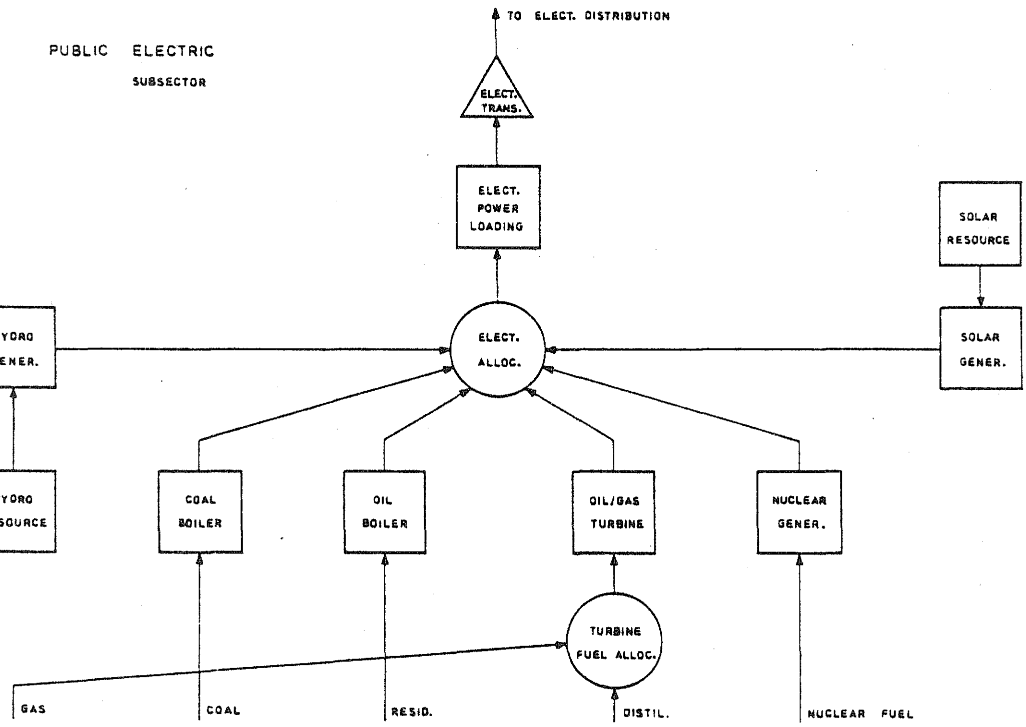


FIG. 4 — PUBLIC ELECTRIC SUBSECTOR NETWORK

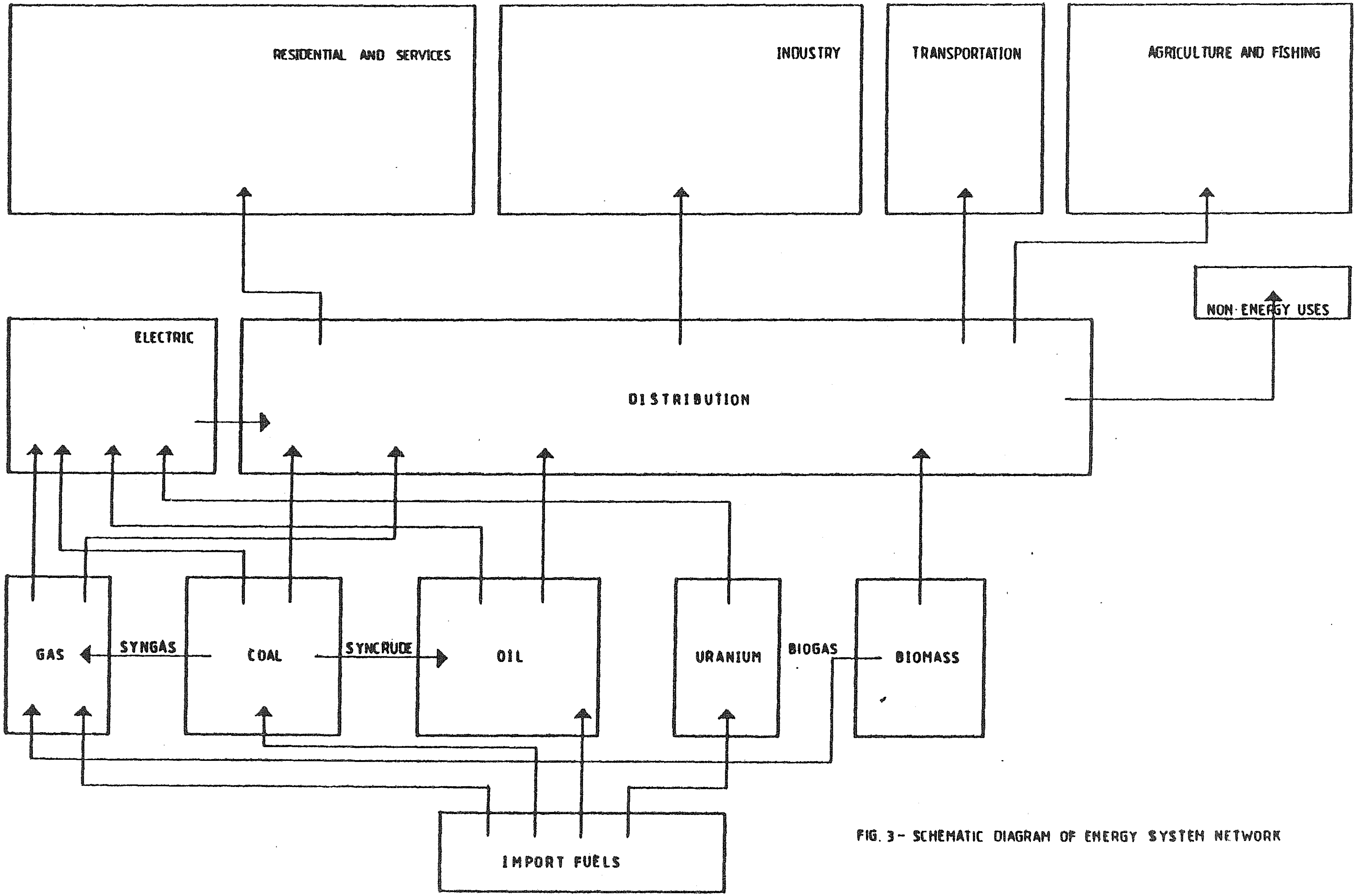


FIG. 3 - SCHEMATIC DIAGRAM OF ENERGY SYSTEM NETWORK

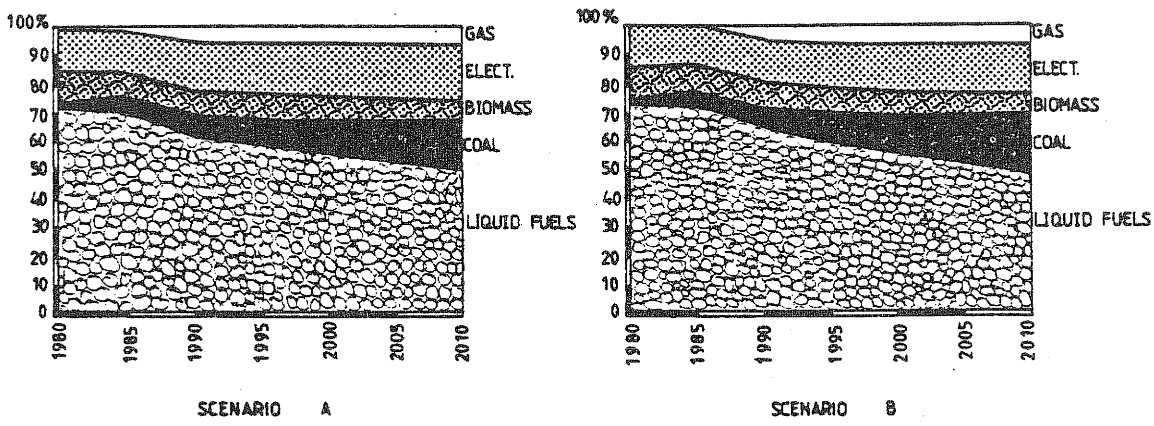


FIG. 5 — FINAL ENERGY CONSUMPTION

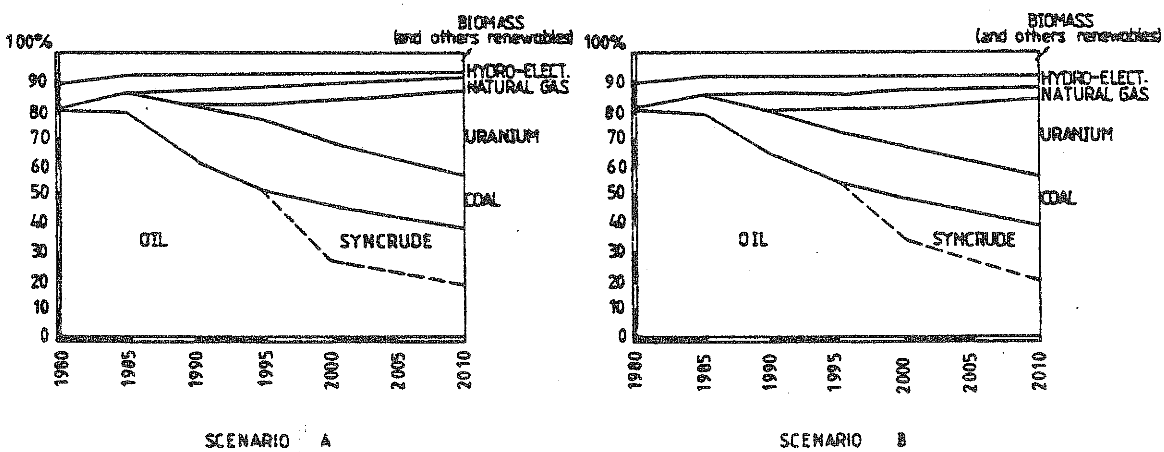


FIG. 6 — PRIMARY ENERGY CONSUMPTION

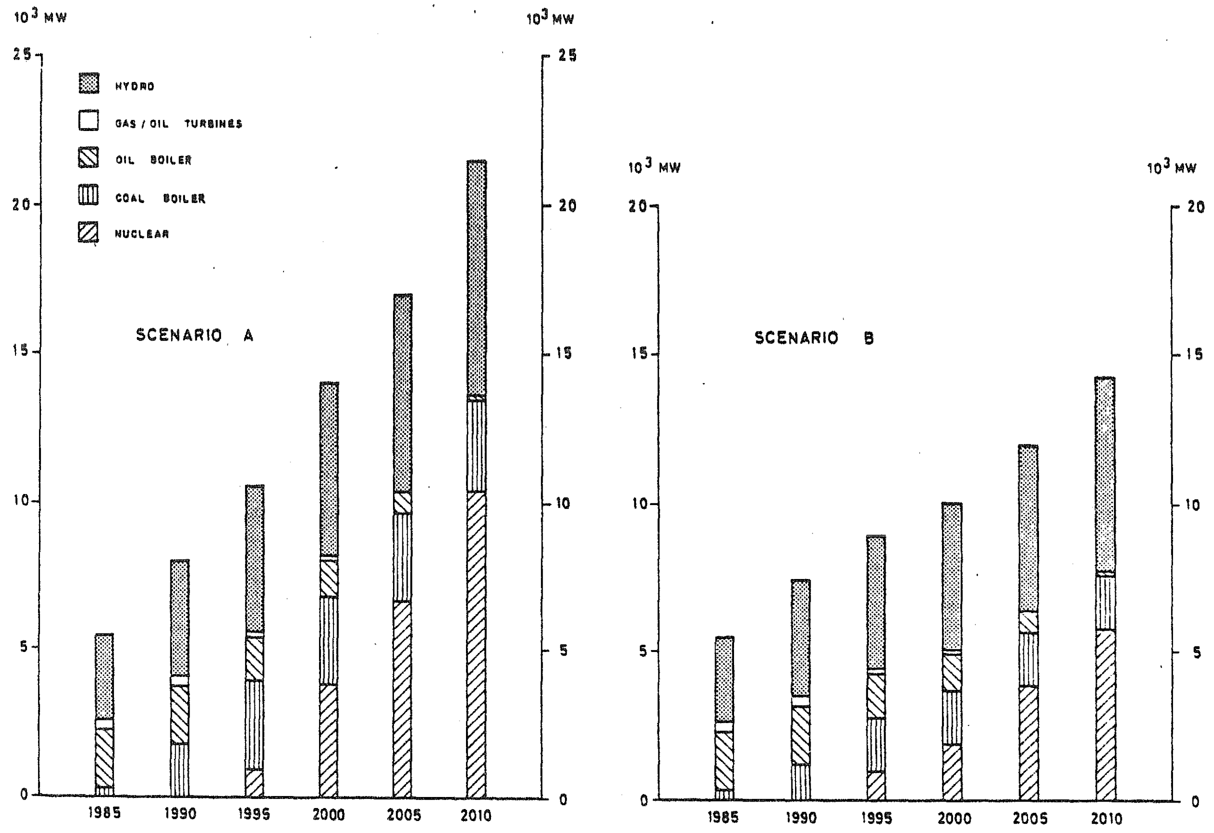


FIG. 7 — INSTALLED CAPACITY BY PLANT TYPE

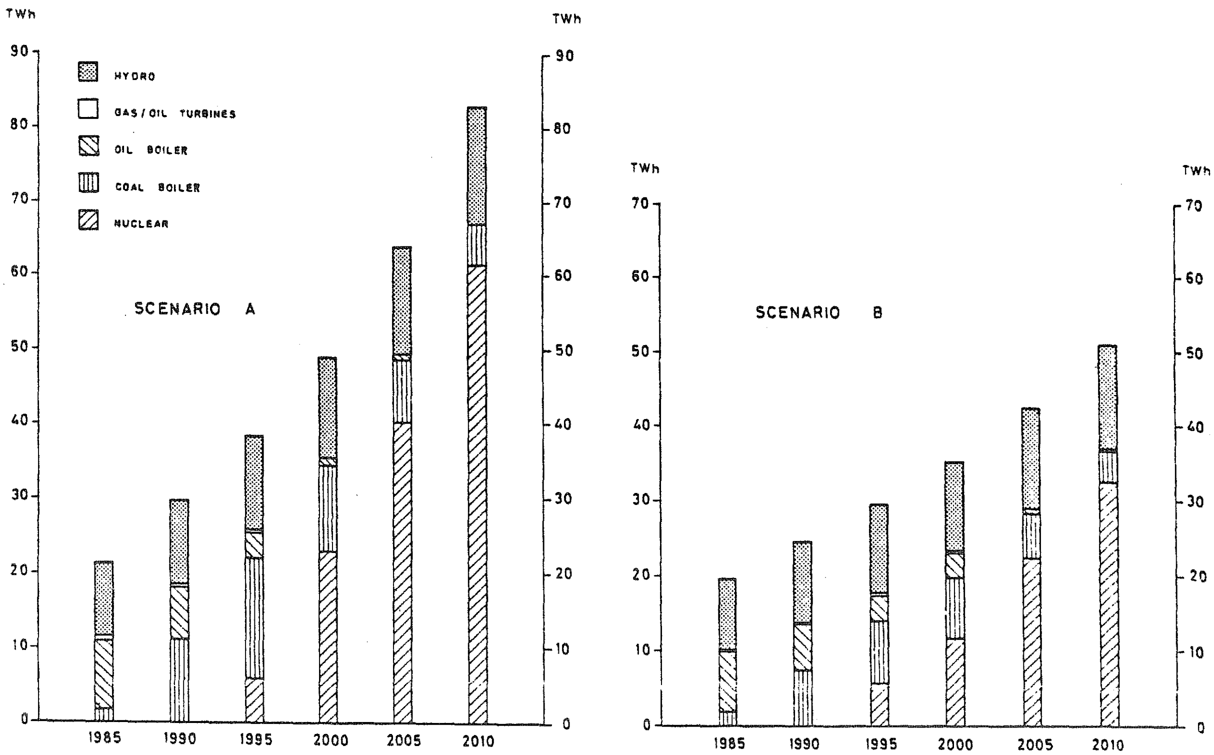
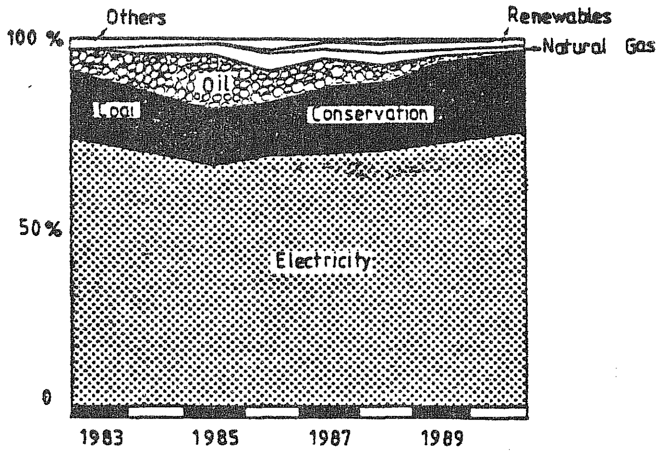
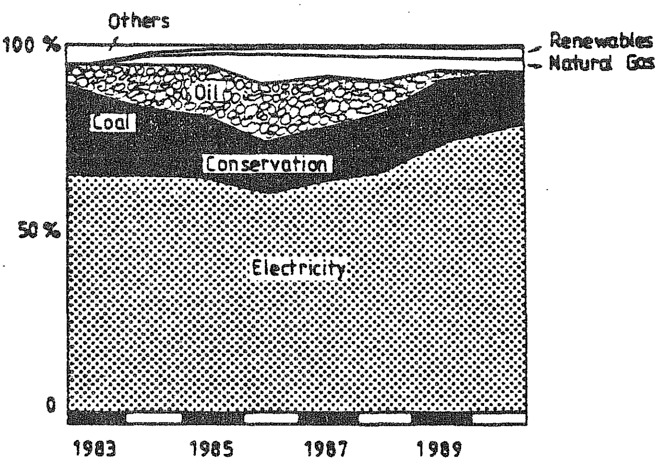


FIG. 8 — ANNUAL GENERATION BY PLANT TYPE
AVERAGE HYDROLOGICAL CONDITIONS



SCENARIO A



SCENARIO B

FIG. 9 - ENERGY SECTOR INVESTMENT PROGRAM

1983 — 1990

A NOVEL AND EFFICIENT TECHNIQUE FOR THE EXACT EVALUATION OF LOLP AND PRODUCTION COSTS IN GENERATION PLANNING

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ABSTRACT

A new probabilistic simulation technique for calculating loss of load probability (LOLP), expected energy generation and fuel cost for a generation system is described in this paper. The new method samples the daily load for a period and assigns to each sample equal probability. The resulting probability density function of demand is then divided into segments of equal capacity. The capacity of each segment is equal to the capacity of the smallest unit in the system and/or the common factor of capacity of all units. For each segment, the zeroeth and first order moments of demand are evaluated from which the LOLP and expected unit generation may be directly obtained. As each unit is committed these segments are shifted appropriately and the zeroeth and first order moments recomputed. The proposed method is many times computationally more efficient than the commonly used Booth-Baleriaux method and almost as computationally efficient as the cumulant method based on the Gram-Charlier series but without the inherent inaccuracies of a series expansion. The results of the proposed method may be considered to be exact. The method is applied to a modified IEEE RTS and the results compared with those obtained from the Booth-Baleriaux method as well as the cumulant method.

INTRODUCTION

An important advance in probabilistic simulation for generation planning was the introduction by Baleriaux et al. [1], of a technique to consider random outages of generating units. The method was further refined by Booth [2]. The method rests heavily on obtaining a load duration curve (LDC) and the corresponding load distribution function. By considering the outages of generating units as contributing to the demand, the notion of equivalent demand is defined. This equivalent load may be viewed as an augmented load caused by the random outages of generating units. Appropriate areas under the probability distribution of demand are used to obtain expected unit energy generation. Units are loaded according to a merit order decided upon their average incremental cost. The equivalent load is obtained by a convolution formula given in terms of a recursive algorithm. The Booth-Baleriaux technique provides the energy generated by each unit as it is committed to meet the demand, the system LOLP as well as the expected amount of unserved energy.

More recently Rau et al. [4] have introduced the so-called cumulant method using the Gram-Charlier expansion. The basic technique rests on the fact that the cumulants of the sum of independent random variables (RVs) are equal to the sum of the cumulants. The basic technique is based on a normalized LDC. The method has been proven to be computationally very efficient and reasonably accurate. However, the method may give problems in generating systems with low FORs and small number of units which disparate capacities. Multimodal load shapes

*Presently with the International Atomic Energy Agency, Vienna, Austria will also cause difficulties in approximating the load distribution. As a result negative values for LOLP as well as expected energy generation for the peaking units may occur.

Stremel et al. [6] have considered a variation of the cumulant method which begins with the chronological demand curve and obtains a probability density function (PDF) of demand and the corresponding cumulants. The moments and cumulants of the load PDF are obtained directly by sampling the chronological demand every hour (or any other time interval) and assigning to each sample equal probability. Discounting the time taken to order the loads to obtain an LDC, both variations of the cumulant method are as computationally efficient.

The proposed technique as described in this paper is based on obtaining a PDF of demand by sampling the daily chronological demand curve every hour or any other appropriate time interval. The demand is then subdivided into segments of equal capacity. The capacity of each segment is equal to the common factor of capacity of all the units. In most cases this common factor corresponds to the capacity of the smallest unit. If all units are of different size, the segment size must be 1 MW. To decrease the computational requirements, unit aggregation or rounding-off of unit capacity may be considered. In any case, even with a 1 MW segment size, the computational requirements are very reasonable.

To obtain the LOLP, unserved energies and unit generation, the method obtains the zeroeth and first order moments corresponding to each capacity segment. As the load is sampled, these two moments are calculated and added to the previous moments in order to obtain the initial moments of unserved demand. As the units are committed, the zeroeth and first order moments for each segment are modified by a very simple algorithm. Thus the convolution process is elegantly simulated by very simple modifications in the zeroeth and first order moments. Similarly for deconvolution.

The new method avoids the inherent inaccuracies present in the evaluation of unserved demand when using a numerical convolution formula or series approximation such as the Gram-Charlier expansion. Multistate representation of units and multiblock loading, for a better model of economic dispatch, to account for the varying nature of incremental cost with demand, are easily incorporated in the proposed method.

The technique has been applied to a modified IEEE RTS [7] and the results compared with those obtained by the Booth-Baleriaux method based on a polynomial approximation of the LDC and numerical integration as well as the cumulant method based on the Gram-Charlier Type A series using eight cumulants.

THE NEW METHOD

The starting point for this method is the daily chronological load curve for a period, the representation of generating units as well as the loading order based on their average incremental cost. Moreover, the segment size must be also defined. The method will be fully described with a simple example.

Consider the daily hourly load for a system (typical winter day of the IEEE RTS) as shown in Fig. 1.

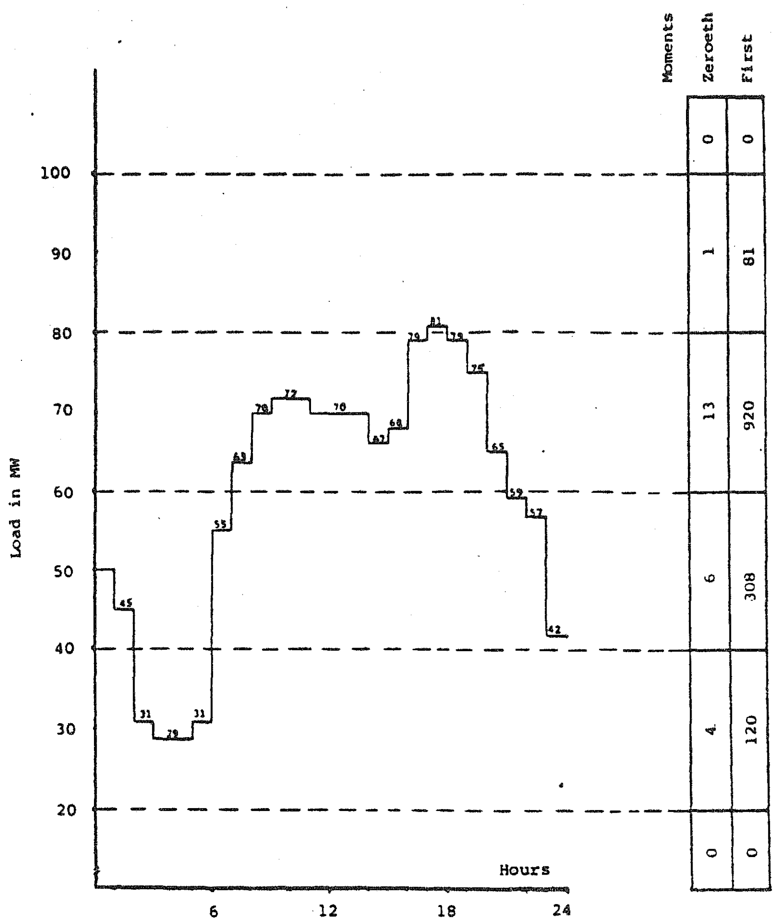

Fig. 1 - Daily Hourly Load Profile

The generating system consists of the following units and FORs as shown in Table I.

Table I

Generating System Description for Sample System

Unit	Capacity MW	FOR %	Utilization
1	20	10	Base
2	40	15	Intermediate
3	40	20	Peaking

By assigning to each sampled hour of Fig. 1 equal probability; e.g. 1/24 in this case, a PDF of demand is obtained as shown in Fig. 2

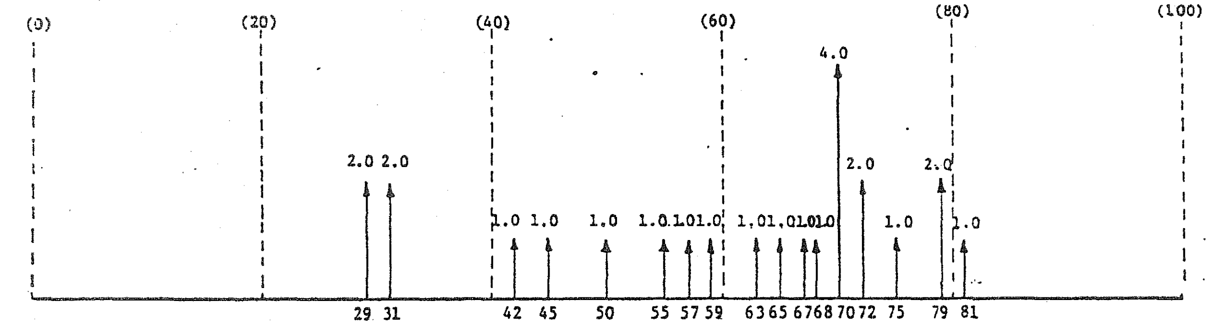

Fig. 2 - PDF of Hourly Loads (all impulses to be divided by 24)

As can be seen from Fig. 1, there are two joint occurrences of the 29 MW load and, therefore, it is assigned a probability of 2/24. Continuing in a similar manner all the probabilities for each impulse of Fig. 2 are defined.

The initial unserved demand is equal to the first moment of the PDF of Fig. 1. This is easily calculated as:

$$UD_0 = (2x29+2x31 + \ldots + 1x81)/24 = 1429/24 \text{ MW}$$

For 24 hours the unserved energy is thus

$$UE_0 = 24x1429/24 = 1429 \text{ MWh}$$

Loading Unit 1, first in the loading order, gives rise to a PDF of equivalent demand as shown in Fig. 3.

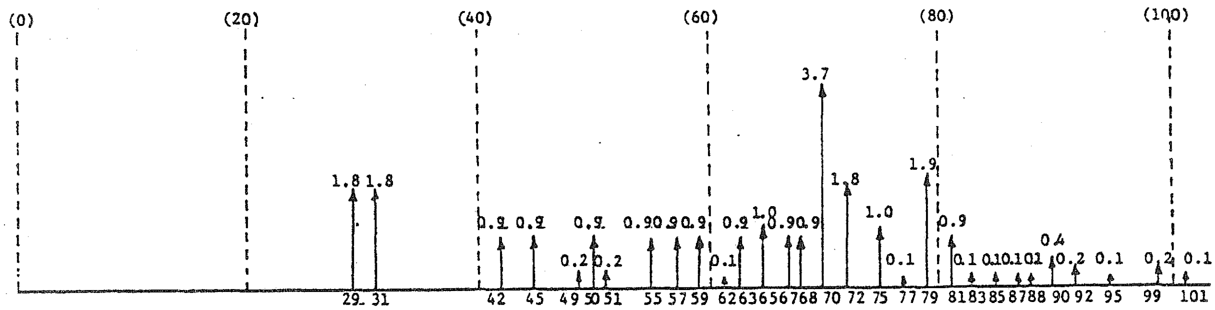

Fig. 3 - PDF of Equivalent Load After Loading Unit 1 (all impulses to be divided by 24)

The impulses have practically doubled after the convolution process, as evidenced by Fig. 3. By subtracting 20 MW (the capacity of Unit 1) from all load levels of Fig. 3, the unserved demand after convolution of Unit 1 is

$$UD_1 = (1.8(29-20)+1.8(21-20) + \ldots + 0.1(101-20))/24 = 997/24 \text{ MW}$$

The unserved energy after convolution of Unit 1 is therefore:

$$UE_1 = 24 \times 997/24 = 997 \text{ MWh}$$

The expected energy generation of Unit 1 is the difference of unserved energies before and after convolution; thus

$$E_1 = UE_0 - UE_1 = 1429-997 = 432 \text{ MWh}$$

In a similar way, the rest of the units are convolved and the unserved energies and expected unit generation obtained. It is worthwhile to note that impulses below committed capacity are not needed to evaluate the unserved demand; therefore, it is not necessary to keep track of these impulses. As a result the number of impulses may be reduced at each stage of the convolution process as will become clearer later.

To calculate LOLP, the impulses lying to the right of installed capacity are added. In Fig. 3, with only the 20 MW unit committed, the LOLP is given by

$$\text{LOLP} = (1.8+1.8 + \dots + 0.1)/24 = 24/24 = 1$$

A New Convolution Technique

The brute force method of convolution previously described is a formidable task. For N load levels and M two state generating units the total number of impulses to be considered may be as high as $N\text{x}2^M$.

To avoid the excessive increase in the number of impulses an elegant technique of convolution has been developed. This method is based on the knowledge of the zeroeth and first order moments of the PDF of unserved demand.

An important step in the application of the new method is the selection of the segment size. The size of the segments must be equal to the common factor of capacity or capacity blocks (for multiblock loading) of all units. In the example being considered, the units are loaded in one block. The capacity of the smallest unit is 20 MW which is also a common factor and hence the segment size is 20 MW. This segment size is depicted in Figs. 1 and 2. In the computer algorithm all segments lying below base load need not be carried since the zeroeth and first order moments are zero. Similarly, only one segment need be carried after installed capacity.

As each unit is committed, the process of convolution demands that the PDF of demand be shifted by the unit capacity and be multiplied by the unit FOR. The final PDF of equivalent loads is obtained by summing to this shifted PDF the original PDF multiplied by unit availability.

The new method does this shifting by modifying the moments in each segment. It is well known [5] that when PDFs are shifted the zeroeth order moment remains unchanged but the first order moment is modified. Thus, for a segment k

$$m_0^{new}(k) = m_0^{old}(k)$$

$$m_1{}^{new}(k) = m_1{}^{old}(k) + \text{shift} \times m_0{}^{old}(k)$$

where

$m_1{}^{new}(k)$ = shifted first moment

$m_1{}^{old}(k)$ = original first moment in segment k

$m_0{}^{old}(k)$ = original zeroeth moment in segment k

Consider Fig. 4(a) which depicts schematically the zeroeth and first order moments of load of Fig. 2. Six segments have been considered in total. One above installed capacity, four between installed capacity and base load and another below base load. This first segment, whose moments are zero need not be carried through in the computational process. For more realistic systems several segments may exist below base load.

Considering Fig. 4(a), note that the zeroeth and first order moments are obtained in a straightforward manner. For the 4th segment these two moments are from Fig. 2

$$m_0 = (1+1+1+1+4+2+1+2)/24 = 13/24$$

$$m_1 = (63\text{x}1+65\text{x}1 + \ldots + 79\text{x}2)/24 = 920/24$$

Consider now Fig. 4(b) which shows the effect of committing the 20 MW unit. The shifted moments are obtained from Eq. (1). For the second shifted segment in Fig. 4(b) these moments are

$$m_0 = 4/24$$

$$m_1 = 120/24 + 20\text{x}4/24 = 200/24$$

In a similar way the two moments for all other segments in Fig 4(b) are obtained

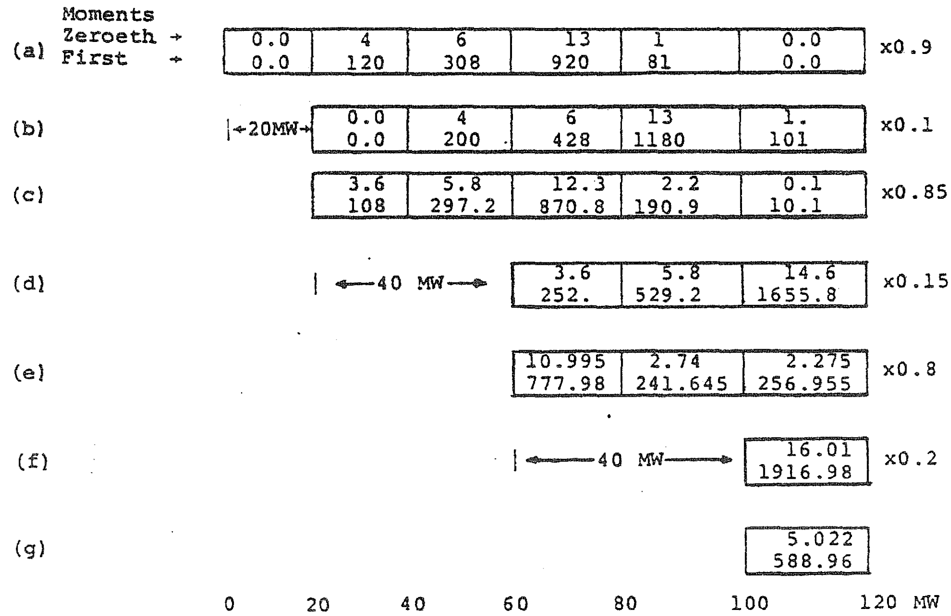

Fig. 4 - Schematic of Evaluation Procedure
(all numbers in boxes to be divided by 24)

Multiplying each moment in each segment of Fig. 4(a) by the availability of the unit, p=0.9, and each moment in each segment of Fig. 4(b) by the FOR of the unit, FOR=0.1, and summing the corresponding segments, Fig. 4(c) is obtained.

Recalling the procedure to evaluate the unserved demand, one is interested in the zeroeth and first order moments of unserved demand; i.e., the moments of the PDF lying to the right of committed capacity. Therefore, it is not necessary to know the moments of the individual segments to the left of committed capacity, as shown in Fig. 4(c). However, this is only true when unit deconvolution is not contemplated.

A general expression for unserved demand may be written as

$$UD_{CU} = \sum_{j=s}^{NS} m_1 - \left(\sum_{j=1}^{CU} C_j \right) \left(\sum_{j=s}^{NS} m_0 \right)$$

where

NS = total number of segment
CU = total number of committed generating units
s = number of committed segments corresponding to a generating unit

From Fig. 4(a) the initial unserved demand is thus

$$UD_0 = \sum_{j=2}^{6} m_1 - \left(\sum_{j=2}^{1} C_j \right) \left(\sum_{j=2}^{6} m_0 \right)$$

$$= (108+297.2+870.8+190.9+10.1)/24$$
$$- (20)\ (3.6+5.8+12.3+2.2+0.1)/24 = 997/24 \text{ MW}$$

A general expression for the expected unit energy generation is the expected energy generation of Unit 1 is thus

$$E_1 = T(UD_0 - UD_1) = 24\ (1429-997)/24 = 432 \text{ MWh}$$

Unit 2 is committed next. This unit has a capacity C_2=40 MW and FOR=0.15. Fig. 4(d) is obtained from 4(c) by shifting the segments by 40 MW. Thus for the first shifted segment in Fig. 4(d) one gets

$$m_0^{new} = 3.6/24$$

$$m_1^{new} = (108+40 \text{x} 3.6)/24 = 252/24$$

Note that the last shifted segment is Fig. 4(d) combines the last three segments of Fig. 4(c).

Fig. 4(e) is obtained by multiplying all moments in each segment of Fig. 4(c) by p=0.85 and those of Fig. 4(d) by FOR=0.15. Note that segments below 60 MW of committed capacity are not retained since they are not required.

The unserved demand after convolving the second is from Fig. 4(e) and Eq.(2) given by

$$UD_2 = \sum_{j=4}^{6} m_1 - (\sum_{j=1}^{2} C_j)\ (\sum_{j=4}^{6} m_0)$$

$$= (777.98+241.645+256.955)/24$$
$$- (20+40)(10.995+2.740+2.275)/24 = 315.980/24 \text{ MW}$$

The expected energy generation of Unit 2 is thus

$$E_2 = T(UD_1-UD_2) = 24(997-315.98)/24$$
$$E_2 = 681.020 \text{ MWh}$$

The last unit to be committed is a 40 MW with FOR=0.2. Fig.4(f) shows the effect of shifting the segments of Fig.4(c) by 40 MW. The only segment produced combines the three last segments of Fig. 4(e). Multiplying all moments in all the segments of Fig. 4(e) by p=0.80 and those in Fig. 4(f) by FOR=0.2 and adding corresponding segments produces Fig. 4(g).

The unserved demand after committing this last unit is

$$UD_3 = \sum_{j=6}^{6} m_1 - (\sum_{j=1}^{3} C_j)\ (\sum_{j=6}^{6} m_0)$$

$$= 588.96/24 - (20+40+40)\ (5.022)/24 = 86.760/24 \text{ MW}$$

The expected energy generation of Unit 3 is thus

$$E_3 = T(UD_2-UD_3) = 24(315.980-86.760)/24$$
$$E_3 = 229.220 \text{ MWh}$$

The expected energy generation is

$$E_T = E_1+E_2+E_3 = 1342.240 \text{ MWh}$$

The energy balance (EB) is thus

$$EB = 1429 - (1342.240+86.760) = 0 \text{ MWh}$$

The system LOLP is simply the zeroeth moment in Fig. 4(g). Thus

$$LOLP = 5.022/24 = 0.20925$$

In the computer algorithm the period T is not carried through to avoid round-off errors. It is important to emphasize that the LOLP and expected energies evaluated are exact. A detailed analysis of this simple system will give the same answers.

One comment about obtaining Fig. 4(a) from the chronological demand. The zeroeth and first order moments in each segment of Fig. 4(a) are obtained as the load curve is sampled. For each interval corresponding to each segment the moments are added as the load is sampled. As mentioned previously an hourly load sample is used in this example. For a more accurate load representation the load curve may be sampled at shorter time interval. The boxes to the right Fig. 1 show the zeroeth and first moment of the load. These boxes are filled up as the load is sampled. In this manner the load does not have to be ordered as in Fig. 2. For a multistate representation, the shifting of the segments must be performed for each state and multiplied by the appropriate probability.

Multiblock Loading of Generating Units

In order to better simulate the economic dispatch procedure a useful stratagem is to load the units in capacity blocks. Each block may have a different average incremental cost. Clearly the capacity blocks may occupy nonadjacent positions in the loading order of merit. The basic information in the simulation procedure of multiblock loading is that higher order blocks cannot be loaded until lower blocks have been committed. To correctly account for this dependency lower order blocks must first be deconvolved before the combined lower and higher blocks are convolved. As explained by Zahavi [3] , the deconvolution of the lower blocks of a unit is necessary for the commitment of the upper block in order to avoid the convolution of the higher block against its own outage.

Consider the standard convolution formula

$$f_z(x) = p_i\, f_y(x) + q_1\, f_y(x-C_i)$$

where

$f_y(x)$ = PDF of equivalent load prior to loading unit or block of capacity C_i

$f_z(x)$ = PDF of equivalent load after loading unit or block capacity of C_i

p_i = availability of unit or block i

q_1 = $1 - p_i$

For deconvolution of a unit or block capacity C_i Eq.(3) must be used as follows:

$$f_y(x) = \begin{cases} f_z(x)/p_i & 0 \le x \le C_i \\ (f_z(x)-q_i\, f_y(x-C_i))/p_i & C_i < x \le (z-C_i) \\ \text{subtraction from total moments} & (z-C_i) > x \end{cases}$$

Expansion Studies

The load growth from year to year can be easily taken into consideration by modifying the moments. Thus, for year (T+1) the new moments are

$$m_0^{(T+1)} = m_0^{(T)}$$
$$m_1^{(T+1)} = m_1^{(T)}(1+GR)$$

where GR is the annual growth rate. In a similar vein, changes in load factor may be incorporated by independent changes to each segment or group of segments.

NUMERICAL EVALUATION

The system that is analyzed is described in the Appendix. The generation model consists of 32 units included 6 hydroelectric generators of 50 MW each. The dependable energy for each hydraulic unit is limited to 40 GWh for the three month period under consideration. The total installed capacity is 3400 MW, the peak load 2850 MW and the base load 1102 MW. The energy demand is 4163.480 GWh. The loads were sampled every hour.

The expected generated and unserved energies, as well as fuel costs for the new method are shown in Table I. The loading order as specified in this table is obtained from the average incremental costs shown in Table A1 in the Appendix. In Table I the third and fifth columns correspond to the expected energies and fuel costs obtained from the commonly used Baleriaux-Booth method based on a step size of 10MW. Note that the capacity of the smallest unit(s) is 10 MW which is the maximum common factor for all generating units therefore a segment size of 10 MW utilized. The cumulant method utilizes 8 cumulants in the Gram-Charlier expansion.

Table I - Comparison of Expected Energies and Production Costs for Each Unit

		Expected Energy Generation			Production Costs		
Unit No.	Capacity MW	Booth Baleriaux Method GWh	Proposed Method GWh	Cumulant Method GWh	Booth Baleriaux Method 10^6\$	Proposed Method 10^6\$	Cumulant Method 10^6\$
1	400	768.768	768.768	768.768	4.18979	4.18979	4.18979
2	400	768.768	768.768	768.768	4.18979	4.18979	4.18979
3	150	314.496	314.496	314.496	3.36636	3.36636	3.36636
4	150	314.496	314.496	314.496	3.36636	3.36636	3.36636
5	150	312.132	312.165	306.695	3.34106	3.34142	3.28287
6	150	299.913	299.927	295.041	3.21027	3.21042	3.15812
7	350	563.469	563.482	576.156	6.13224	6.13238	6.27031
8	80	113.681	113.687	118.420	1.52401	1.53409	1.59891
9	80	104.805	104.765	108.278	1.41424	1.41370	1.46111
10	80	96.607	96.610	97.778	1.30362	1.30366	1.31942
11	80	89.029	89.031	85.575	1.20136	1.20139	1.15609
12	200	98.889	98.889	85.526*	2.04998	2.04997	1.77294
13	300	240.000	240.000	240.000	0.00000	0.00000	0.00000
14	200	45.556	45.551	47.673	0.94437	0.94427	0.98825
15	200	20.745	20.748	22.745	0.43004	0.43012	0.47150
16	100	5.260	5.259	5.796	0.10968	0.10966	0.12087
17	100	3.084	3.087	3.387	0.06431	0.06437	0.07064
18	100	1.763	1.764	1.847	0.03676	0.03679	0.03851
19	10	0.131	0.131	0.130	0.00337	0.00338	0.00337
20	10	0.123	0.123	0.121	0.00318	0.00317	0.00313
21	10	0.116	0.116	0.112	0.00299	0.00300	0.00291
22	10	0.109	0.108	0.105	0.00281	0.00281	0.00270
23	10	0.102	0.102	0.097	0.00265	0.00265	0.00250
24	20	0.171	0.170	0.158	0.00640	0.00640	0.00593
25	20	0.151	0.151	0.136	0.00568	0.00568	0.00513
26	20	0.135	0.134	0.117	0.00505	0.00505	0.00442
27	20	0.120	0.120	0.101	0.00449	0.00450	0.00370
	TOTAL	4162.617	4162.653	4162.695	36.92085	36.92119	36.85577

* The order of the 200 MW coal fuel unit and the hydro unit are inverted in the cumulant method. Refer to Manhire for a detailed explanation of production costing with energy limited units such as hydro units.

Table II shows a comparison of the total expected and unserved energies, energy balances, system LOLPs as well as total CPU times (IBM 3033).

Table II

Comparison of Results

	Booth-Baleriaux Method	Proposed Method	Cumulant Method
Expected Energy GWh	4162.61740	4162.65288	4162.69562
Unserved Energy GWh	0.82670	0.82725	0.40706
Energy Balance GWh	0.03603	0	0.37745
System LOLP %	0.2886	0.2899	0.2395
CPU Time (seconds)	11.0	0.30	0.28

Note the perfect energy balance of the proposed method as compared to the Baleriaux-Booth method. For the Booth-Baleriaux method decreasing the step size does not improve the solution because of round-off errors. The computational efficiency and accuracy of the proposed method is clearly apparent as Table II shows. It is worthwhile to mention that the CPU time for the new method for a segment size of 1 MW was 0.56 sec with exactly the same results as those shown in Table I and II.

The hydro units, for the selected period, are discharging 240 MWh. Unit 12, therefore, must be fragmented to accomodate these units. Thus, the total expected energy of unit 12, as shown in Table I, is the sum of these two fragments (one of unit 12 was loaded before and the other after the hydro units). The fitting of the hydro units is explained in Manhire [8].

CONCLUSION

This paper has described a powerful, flexible, accurate, simple and efficient method to obtain the expected energy generation, expected unserved energy, LOLP and fuel costs for a system of generating units meeting a certain demand. The method can simulate multistate representations of generating units, combinations of units into aggregate units, as well as multiblock loading for optimum economic dispatch.

The new probabilistic method reduces in an elegant way thousands of impulses into a few segments thus making the convolution process numerically feasible and simpler. Results obtained by the method can be considered to be exact. In combination with computational speed the method may offer a significant improvement for production cost calculations in generation expansion studies.

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APPENDIX

Table A1 - Generation Data for System Studied

Type of Unit	Unit Size (MW)	No. of Units	FOR	Avg. λ ($/MWh)
Nuclear	400	2	0.12	5.45
Coal	350	1	0.08	10.883
Coal	150	4	0.04	10.704
Coal	80	4	0.02	13.494
Oil	200	3	0.05	20.730
Oil	100	3	0.04	20.853
Oil	20	4	0.10	37.500
Oil	10	5	0.02	25.875
Hydro	50	6	0.01	0

Total installed capacity	3400 MW
Peak load	2850 MW
Minimum load	1102 MW
Time duration	2184 hours

The weeks that were used in the description of the load were: weeks 1-8 and 48-52 as defined in [7].

A LINEAR PROGRAMMING MODEL OF THE PACIFIC NORTHWEST ELECTRICAL POWER SYSTEM

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Abstract

On December 5, 1980, Congress passed the Pacific Northwest Electrical Power Planning and Conservation Act, which introduced a new era in regional electrical resource planning and cooperation in the Pacific Northwest (PNW). The Act created a Regional Council, containing two representatives from each of the four PNW states, which was directed to develop a PNW regional electrical power plan. In developing an electrical power plan, the Council will need to know which of the possible electrical generating plants currently under construction, or in the planning stage, are the least cost method of meeting future regional electrical requirements. Not only does the Council need to determine which generating plants should be built, but it also needs to know when the plants should be built.

This paper outlines a linear programming (LP) model which determines an optimal construction schedule of electrical power resources for the PNW and provides estimates of the marginal cost of supplying electrical energy and generation capacity in the PNW. The model optimizes the decision-making process for the PNW electrical production in two respects--planning and operation. In particular, it determines both the total generating capacity by plant type for the PNW and the dispatch of each plant type, in a fashion which minimizes the present value of the total costs of construction and operation (less revenues from sales outside the region). The solution assures that adequate capacity is constructed to meet peak loads, and that plants are operated sufficiently to meet forecasted overall load requirements. Although off-peak loads, peak loads, and hydro generating capabilities are considered to be fixed and known, the model has been run with different scenarios for those factors in order to evaluate the impact of uncertainty.

A. Model Structure

The analysis is carried out over eight time periods (called "segments") per quarter, four quarters per year, for the ten operating years 1982-83 through 1991-92.

Ten different plant types are considered by the model. These types are: (1) baseload plants, including Trojan, Centralia, Colstrip #1, #2, #3, and #4, and Jim Bridger; (2) intermediate plants, including Boardman #1 and #2, Valmy #1 and #2, and Creston #1 and #2; (3) peaker plants such as combustion turbines; (4) the hydro system; (5) renewables; (6) imports; (7) exports; (8) WPPSS #1; (9) WPPSS #2; and (10) WPPSS #3.

The following table lists the characteristics of the above-mentioned plants.

Table 1

Plant Name	Status	Earliest Allowable In-Service Date	Capacity Rating (mw)	Fuel
Boardman #1	Existing	---	530	Coal
Centralia	Existing	---	1280	Coal
Colstrip #1	Existing	---	165	Coal
Colstrip #2	Existing	---	165	Coal
Hydro	Existing	---	31000	Hydro
Imports	Existing	---	2600	Coal
Jim Bridger	Existing	---	667	Coal
Peakers	Existing	---	1106.3	Gas & Oil
Trojan	Existing	---	1080	Nuclear
Valmy #1	Existing	---	121	Coal
Renewables	Under Consid.	July 1982	100	Misc.
Colstrip #3	Under Constr.	Jan. 1984	490	Coal
WPPSS #2	Under Constr.	July 1984	1100	Nuclear
Valmy #2	Under Constr.	Oct. 1984	121	Coal
Colstrip #4	Under Constr.	July 1985	490	Coal
WPPSS #1	Under Constr.	April 1987	1250	Nuclear
Creston #1	Under Consid.	July 1987	500	Coal
WPPSS #3	Under Constr.	Oct. 1987	1240	Nuclear
Creston #2	Under Consid.	April 1989	500	Coal
Boardman #2	Under Consid.	July 1989	530	Coal

The construction decisions for the non-existing plants are captured by the variable KAP_{pqt}, which represents the total generating capacity (of both existing and future purchases of currently non-existing plant) in the PNW of plant type p, for quarter q of year t.

The operational decisions are captured by a number of variables. First, the variable O_{psqt} represents the capacity (in mw) used to meet the PNW load, by plant type p, segment s, quarter q, and year t. Second, the variable OS_{psqt} represents the capacity (in mw) used to meet firm committed energy sales and also opportunity energy sales outside the region, by plant type p, segment s, quarter q, and year t. Third, the variable KS_{pqt} represents capacity (in mw) used to meet current firm demand sales and new firm capacity sales outside the region, by plant type p, quarter q, and year t.

The principal considerations for construction and operation of the PNW generating system are that enough capacity must be installed to meet peak demand (plus reserves), and that the generating plants must be operated sufficiently to meet load.

$$(1) \quad \sum_{p=1}^{10} KAP_{pqt} \geq P_{qt} + r_{qt} * P_{qt} + \sum_{p=1}^{10} KS_{pqt}$$

where P_{qt} is the peak demand of the region (in mw) forecasted for quarter q of year t, and r_{qt} is the percentage of forecasted peak demand which (under accepted planning criteria) must be held in reserve.

On the other hand, the region's loads plus all sales cannot exceed the current generating capacity.

(2) $O_{psqt} + OS_{psqt} + KS_{pqt} \leqq (1 - f_p)*(KAP_{pqt} - M_{pqt})$

where f_p is the forced outage rate for plant type p, and M_{pqt} is the scheduled maintenance (in mw) of plant type p in quarter q of year t.

For plants yet to be constructed, maintenance schedules are not known. Instead of attempting to prejudge the optimal time of the year for maintenance, the operation of such plants is constrained to leave room for maintenance.

(3a) $\sum_{s=1}^{8} (O_{psqt} + OS_{psqt})*H_{s_q} \leqq a_p*KAP_{pqt}*H_q$

where a_p is the expected availability rate of plant type p (incorporating both the forced outage rate and the average downtime for maintenance), H_q represents the number of hours in quarter q, and H_{s_q} represents the number number of hours in segment s of quarter q. (Thus, $H_q = \sum_{s=1}^{8} H_{s_q}$.)

For other types of plants, the constraint is binding on the energy production over a full year:

(3b) $\sum_{q=1}^{4} \sum_{s=1}^{8} O_{psqt} + OS_{psqt})*H_{s_q} \leqq \sum_{q=1}^{4} a_p*KAP_{pqt}*H_q$

Two other constraints treat the installed capacity of the region. First, there is an upper limit on how much capacity is available, as determined by the capacity of existing plants plus the capacity of planned plants (according to current construction schedules and lead times). That upper limit is designated by $ICAP_{pqt}$, yielding:

(4) $KAP_{pqt} \leqq ICAP_{pqt}$ for each plant type p, quarter q, and year t.

Second, because no plants are scheduled to be retired between now and 1992, the capacity by plant type never decreases:

(5) $KAP_{p(q+1)t} \geqq KAP_{pqt}$

The second major consideration is that plants be operated sufficiently to meet the region's load. This is expressed simply by:

(6) $\sum_{p=1}^{10} O_{psqt} \geqq L_{sqt}$

where L_{sqt} is the load (in mw) demanded in the region in segment s, quarter q, and year t.

The operation of the hydro system is constrained by the expected energy E_{qt} to be available in quarter q of year t under conventional hydro agreements, the amount of energy F_{qt} stored for the next quarter, and the amount of energy B_{qt} used in the prior quarters, as follows:

$$(7) \quad \sum_{p=1}^{8} (O_{psqt} + OS_{psqt}) * H_{s_q} \leqq E_{qt} - F_{qt} + F_{(q-1)t} - B_{qt} + B_{(q+1)t}$$

for p equal to plant type hydro. In addition, storage limits of 2000 AMW are imposed for within year storage, and storage limits of 1000 AMW for between year storage.

Outside sales of energy and capacity are bounded underneath by committed sales, and above by the intertie capacity plus any committed energy contracts from California to the PNW. The intertie currently consists of two AC transmission lines of roughly 1250 mw apiece and a DC transmission line of 1556 mw capability. The transmission lines allow electricity to be sent in either direction between California and the PNW.

Thus,

$$(8) \quad COS_{sqt} \leqq \sum_{p=1}^{10} OS_{psqt} \leqq INT_{qt} + IMP_{qt}$$

where COS_{sqt} represents committed outside sales of energy and IMP_{qt} is the firm energy sales committed from California to the PNW. The INT_{qt} figure represents the capacity of the intertie in quarter q, in year t, and also includes the top quartile of the Direct Service Industries' load. The Direct Service Industries are a group of industrial customers who buy power directly from the Bonneville Power Administration. The top quartile is arithmetically included in the intertie and represents the fact that should surplus energy exist, the top quartile would be an additional market that could be served by that surplus energy. The price per kwh of the outside energy sales was assumed to be 27.5 mills/kwh and was escalated at the turbine fuel price index.

$$(9) \quad CSK_{sqt} \leqq \sum_{p=1}^{10} KS_{psqt} \leqq INT_{qt} + IMP_{qt}$$

where CSK_{sqt} represents committed outside sales of capacity. The price of capacity was assumed to be 90 percent of the quarterly economic cost of capital of a peaker plant.

Last, but not least, is the objective function to be minimized. Mathematically the objective function is represented by the following:

$$\sum_{t=1}^{10} \sum_{q=1}^{4} \sum_{p=1}^{10} (CAP_{pqt})(KAP_{pqt}) - (CSL_{qt})(KS_{pqt})$$

$$\sum_{t=1}^{10} \sum_{q=1}^{4} \sum_{s=1}^{8} \sum_{p=1}^{10} H_{s_q}(R_{pqt})(O_{psqt}+OS_{psqt})-(OS_{psqt})(V_{qt})$$

Where CAP_{pqt} represents the quarterly capital carrying cost per mw of plant type p, in quarter q, in year t. For existing plants, the capital cost was calculated using historic construction cost information.

For new plants, CAP_{pqt} represented the quarterly "economic" carrying cost per mw of the construction cost needed to complete the plant beginning July 1, 1982. The economic carrying cost was calculated using the basic method recommended by the National Economic Research Associates (NERA). The method computes the carrying cost by netting out the inflation element of nominal interest rates to derive real interest rate estimates.

CSL_{qt} is the price charged for selling capacity to the Pacific Southwest in quarter q, in year t. The price was assumed to be 90% of CAP_{pqt} for the turbines plant type.

The R_{pqt} term in the second part of the objective function is the variable operation cost of plant p, in quarter q, in year t, in \$/mw-hr. V_{qt} is the price charged in \$/mw-hr for energy sold to the Pacific Southwest. A price of \$27.5/mw-hr, escalated at the overall rate of the turbine operating cost index, was assumed for outside energy sales.

The LP model will be able to provide three main results which will be useful in determining an overall regional energy plan.

1) Marginal cost of reserve capacity cost estimates.

2) In-service dates for new plants.

3) Marginal cost of energy cost estimates.

<u>Marginal Cost of Reserve Capacity Estimates</u>.

The marginal cost of reserve capacity cost estimates will be generated through the first constraint.

$$(1) \quad \sum_{p=1}^{10} KAP_{pqt} \geqq P_{qt} + r_{qt} * P_{qt} + \sum_{p=1}^{10} KS_{pqt}$$

This constraint will provide a shadow price which equals the marginal cost of demanding an additional mw of pure capacity. The shadow price will in general equal the least capital cost resource available to provide capacity. The marginal cost of capacity is a useful piece of knowledge since it represents the benefits to the region of implementing policies which reduce peak load demands. Also, in combining the marginal cost of capacity with the additional marginal cost of providing peak energy loads vs. off-peak energy loads, the total marginal cost of supplying an additional mw of peak demand is derived.

Demand Cost = Pure Marginal Cost of Capacity plus (Peak Marginal Cost of Energy minus Off-Peak Marginal Cost of Energy) * Duration of Peak Load

and

Energy Cost = Off-Peak Marginal Cost of Energy.

The dual price to the first constraint will be binding when supplying an additional mw of peak load causes the region to add a mw of capacity or to reduce capacity sales by one mw.

In-Service Dates For New Plants.

The model determined in-service dates for the new plants will be provided through the values of KAP_{pqt}. KAP_{pqt} represents the mw capacity held by the PNW of plant type p, in quarter q, in year t. When a plant is available for service through the fourth constraint, (4) $KAP_{pqt} \leqq ICAP_{pqt}$ the LP model will determine if it is cost effective to add the plant to the region.

Marginal Cost of Energy Estimates.

Finally, the marginal cost of energy estimates will be generated through the sixth constraint:

$$(6) \quad \sum_{p=1}^{10} O_{psqt} \geqq L_{sqt}$$

The shadow price in "raw" form of the above constraint represents the additional cost to the region of producing an additional mw of output (electricity) for a duration of H_{s_q} hours of load in segment s, in quarter q, in year t. Energy cost, which is in units of $/mw-hr, is the additional cost of demanding an additional mw for one hour. Therefore, the "raw" shadow prices need to be divided by the hours in the segment H_{s_q} in order to have the proper units.

The high, medium, and low marginal cost of energy estimates provided later were determined from taking the average of the marginal cost of energy estimates derived in the manner described above of each of the five water year scenarios for each of the ten years. Each water year scenario provided a marginal cost estimate for each quarter, in each of the ten years. By averaging the 50 marginal cost of energy estimates (5 water scenarios * 10 marginal cost estimates per water scenario) an average marginal cost of energy estimate is generated for each of the four quarters. The average marginal cost of energy estimate is useful because it can determine the benefits to the region of adopting energy conservation policies.

Specifically the "High" column represents the highest average marginal cost estimate (an average of the marginal cost estimates over the ten year time frame per quarter) among the five water scenarios given the load forecast. The "Low" column correspondingly represents the lowest ten year quarterly average marginal cost estimate among the five water scenarios.

The "Average" column represents the average marginal cost estimate over all of the five water scenarios during the ten year time period.

The above three pieces of information generated by the LP model will be instrumental in developing a regional energy plan and in analyzing the benefits of currently adopted conservation activities.

Models

Using the basic regional LP model described above, fifteen different scenarios were analyzed to provide a range of cost estimates, using three levels of future load growth and five sets of random water year choices. High, medium, and low load forecasts were taken from "Bonneville Power Administration Forecasts of Electricity Consumption in the Pacific Northwest." This BPA report was published in April of 1982. Five sets of water year choices were derived by randomly selecting, with replacement, one of the 40 water year energy and capacity capabilities ten times.

Results of the Linear Programming Model Without Assuming Current Regional Energy Policy Decisions

Construction Scheduling

In determining a regional energy plan, one of the main aspects of such a plan would be the scheduling of on-line dates for future power plants. Table 2 presents the average on-line service dates for the planned power plants under the low, medium, and high load growths.

The main conclusions drawn from reviewing Table 2 are:

1) More plants are needed to come on-line as load growth increases.

2) Plants need to come on-line sooner as load growth increases.

Table 2

Average In-Service Date Determined Economically Optimal from Regional LP Model

Plant Name	Earliest In-Service Date Allowed	High Load	Medium Load	Low Load
Colstrip #3	3/83	3/84	3/87	4/91
WPPSS #2	1/84	3/84	3/87	*
Valmy #2	2/84	1/89	3/90	*
Colstrip #4	1/85	1/87	2/90	*
WPPSS #1	4/86	1/90	*	*
Creston #1	1/87	4/89	*	*
WPPSS #3	2/87	*	*	*
Creston #2	4/88	1/91	*	*
Boardman #2	1/89	1/91	*	*
Turbine Capacity as of 4/91		6591.8	3881.1	1103.6

*Not In-Service by 4/91

As one might expect, more power plants are needed to come on-line before 4/91 as the rate of load growth increases. And the power plant that comes on-line in each of the load growths (Colstrip #3), is needed to come on-line earlier as load growth increases. One strategy available to the region is to bring Colstrip #3 on-line by 3/84, while maintaining construction on WPPSS #2, Colstrip #4, Valmy #2, and WPPSS #1. As time passes, the status of load growth can be examined to determine the pace of construction on the above plants. Finally, one can observe that there exists some leeway from the earliest date a plant could be in service to the actual date the plant is needed to come on-line. The conclusion that a flexible rate of construction on new plants might be a reasonable energy plan was also reached in a study published on January 20, 1982, written by Watson, et. al., "Power Planning and Uncertainty." On page 12 the study reads: "For there to be greater flexibility in the power planning process, it will be necessary to 'bank' projects for later use and perhaps to slow down or pause in the construction of others." Therefore, a wait-and-see policy would seem to be recommended for power plant construction scheduled.

Marginal Cost Estimates.

Tables 3 and 4 summarize the marginal cost estimates results of the regional LP model combining the five water year scenarios and the low, medium, and high load forecasts. These tables show that:

1) Marginal Cost of Energy Decreases as Load Growth Decreases. The use of more costly operating plants can be avoided as load growth declines. For example, if over the next ten years no new plant was needed to come on line, then the marginal cost of energy would be the fuel cost of existing plants. However, as load growth increases, plants are added to the generation system to avoid operating high variable cost existing plants such as turbines, and to satisfy capacity requirements.

Table 3

Average Marginal Cost of Energy
by Load Forecast
(mills/kwh)

Quarter	High	Medium	Low
July-September	23.29	22.70	19.50
October-December	24.89	24.18	20.88
January-March	20.50	20.01	16.57
April-June	16.06	15.71	12.80

Marginal costs are lowest under low load growth assumptions.

2) Seasonal Demand Cost, is highest January through March, when capacity must be added to meet reserve requirements. The October-December quarter and the April-June quarter is assigned some demand cost when opportunity sales can be made outside the region; the marginal cost of supplying an additional mw of capacity at that time is the sales revenue

forgone. No demand cost exists in July through September since the intertie is fully loaded and no revenue opportunities are lost.

Table 4

Demand Cost
by Load Forecast
($/kw-Quarter

Quarter	High	Medium	Low
July-September	0.00	0.00	0.00
October-December	5.22	5.22	5.22
January-March	23.50	13.52	5.25
April-June	0.86	2.03	0.97

These estimates also include peak/off-peak energy cost differentials.

Conclusion

The planning of a regional generation system to meet future load projections is indeed a complex problem. The results from the LP model indicate that such a plan should be flexible enough to meet various levels of possible load growths and, at the same time, attempt to minimize costs. It is evident that there is a role for LP analysis in regional generation system planning.

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PUMPED STORAGE PLANT MODEL FOR IMPROVEMENT OF THE WASP - III COMPUTER PACKAGE CAPABILITIES

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Abstract

Pumped storage plant model for improvement of the WASP-III computer package capabilities has been presented in this paper. Pumped storage plants are considered either for short term storage or for long term storage. Simulation model for optimal allocation of the short term storage and dynamic programming for optimization of the long term storage operation is proposed.

Introduction

The main objective of electric system expansion planning is to find what type, size and start-up year of new units will satisfy the consumer demand over a planning period with the minimum cost subject to unit, system and fuel availability constraints. As the demand served by electric utility has grown there has been a constant requirement for installing new generating plants. Many of the newer plants are quite different in character from conventional hydro or thermal power plants. Pumped storage units are an example of such a plant. The inclusion within a power system pumped storage hydroelectric plants affects the system's entire structure and operation. These plants rationalize the structure of the system's generating capacity by an increase in the economically justified proportion of efficient base load power (run-of-river, nuclear power plants or unexpensive fossil fuel units) and a corresponding decrease in the capacity of intermediate load plants. Furthermore, pumped storage plants displace peak thermal units such as gas turbine from the peak of the load curve. This rationalizing effect which pumped storage plants have on the structure of a power system is one of the principal economic incentives for their use. This is particularly the case in the power systems with high percentage of run - of - river or nuclear power capacity. The influence of pumped storage plants on the expansion and as a results, on the operation must be taken fully into account in the long - term expansion planning of generating capacity and in the optimization of the system´s operation. The yugoslav electric power system is a good example of such a system. Almost one half of the electric energy is generated by hydro power plants and several nuclear plants are also candidates for the electric power system expansion. Besides already existing pumped storage plants there are some more that may be included into system. Therefore, there is a growing interest for a comprehensive approach to the electric power system planning in Yugoslavia. The research efforts in this field is supported by Union of the Power Industry - ZEP Beograd, and by International Atomic Energy Agenca (IAEA) - Vienna. In addition to the financial support, the professional support and valuable discussion are must appreciated from these both sides.

Problem formulation

The long term electric system expansion planning is becoming more complex, not only because of the larger number of plants, but also because of the more complex characteristics of the new plants. The power sources available for scheduling can include: conventional hydro plants, pumped storage units, fossil fuel thermal plants, nuclear plants, cogeneration plants, coordinated operation with other utilities and diversity interchange contract.

Current WASP version, WASP-III, does not permit the introduction of coordinated operation with other utilities, diversity interchange contracts, cogeneration plants and pumped storage units into the power system planning. In principle, there is nothing to prevent the pumped storage to be treated in the WASP-III in its simulation and optimization procedure in the same way as other units. There are only some additional modification to be made in order to adequately represent the operation of this type of plant, and our efforts are directed allong this line.

The pumped storage plants are limited in capacity but in energy as well. They economic evaluation depent on: type of the system load curve, composition of the generation system, reliability of each unit, reliability of the over - all power system and running cost of all types of units existing or forseen in the system.

The characteristics of a pumped storage plant may be described in the model by means of the following parameters:

P_p - pumping capacity

P_E - generating capacity

E_m - maximum feasible energy generation in a period

η_p - pumping efficiency

η_q - generating efficiency

$\eta = \eta_p \cdot \eta_q$ - cycle efficiency

Q - natural water inflow,if any

V - volume of the reservoir

The pumped storage function may be:

a) Long term storage
b) Short term storage

Long term storage use dump energy from high flow at run-of-river plants to pump some of the excess water to reservoir at high elevation and release stored water in dry season or in high load period to generate power and energy at the storage plant and at downstream plants. Short term storage transfer low cost incremental energy or hydro energy spillage from off-peak hours to peak hours and supply peak hour generation capacity and ready reserve. Two short term cycle types may be considered: daily cycles when the reservoir is filled and emptied every day, and weekly cycles when the reservoir is full and empty only once every week.

In the planning studies the total system generating cost has to be considered. The variations of the total cost that can result from different expansion alternatives in comparison with a reference option is assumed as a measure of the relative value of such alternatives. The best solution is find by an optimization procedure.

The determination of the operation costs in WASP code is excuted through a simulation process which is repeated for a number of periods into which the year has been subdivided. For these calculation the optimum allocation between the pumped storage plant and its base load (thermal or hydroelectric plants) considers the evoluation of the economic efficiency of such combinations and impact of the pumped storage to the characteristics of the power system.

The operation of pumped storage units is inherently chronological. In the WASP model the load duration oriented simulation is used. An inherent loss of chronological informations in associated with this approach.

The presentation of load duration curve and the energy available for pumping and generation in our model are similar as in the WASP-II model.

In the case of base load supplied by thermal plants the break-even point between generation and pumping may be determined by the relation

$$T = (C_{th} - C_p) \cdot \frac{\eta}{1-\eta} \cdot c \,, \quad T > 0$$

where C_{th} is the fixed cost per unit of capacity per unit of time of the thermal plant

C_p is the fixed cost per unit of capacity per unit of time of pumped storage plant

c is the variable cost per unit of energy of the thermal plant

η is the total efficiency factor of the pumping-generating cycle of the pumped storage plant

T is generating time of the pumped storage plant.

Pumped Storage Simulation

In the WASP-III pumped storage plants are left out but logic and procedure of the model are similar to that in WASP-II. Two composite hydro peaking blocks introduced in WASP-III make another difference. However, it is possible to make use of most of the algorithm for the pumped storage treatment already tested in WASP-II.

The main problem of the pumped storage introduction in WASP-III is how to find optimal allocation of the pumped storage in relation to two composite hydro peaking blocks. In the model presented the positioning of two hydro blocks is done first by the existing WASP-III methodology, and the treatment of the pumped storade operation is done next.

The amount of energy produced by aech plant of the power system in the period considered could be calculated from plant loading order and load duration curve. Beside so calculated energy, the energy that could be replaced by the generation of the pumped storage plant and energy that is available for pumping can also be calculated. In the case when the pumped storage plant generates, for the thermal plant considered the load is reduced by generating capacity of the pumped storage plant (Fig.1a). In the similar way but in apposite direction (Fig. 1b) the energy available for pumping purposes can also be determined if the load for the thermal plant considered is increased by the pumping.

If the thermal block considered share the place in the loading order with the hydro peaking block, than this complex situation is refered as fractional case. The calculation of possible pump storage plant generation and possible pumping for the thermal plant considered is in general made by the energy integration in two places: in the actual place and in a displaced position of the thermal plant. This displacement is practically made by the change of the integration limits.

The methodology of WASP-II, followed so far, may accept only one hydro peaking block. In the WASP-III the presence of two hydro peaking blocks may change the extent of calculation of the replaced energy by the pumped storage plant generation and the extent of the calculation of the available energy for pumping in each thermal plant. The essencial of the methodology may be kept the same, but it has to be extended over the second hydro block, also.

In the calculation of the possible energy generation by pumped storage plant in many cases the second hydro block will not be involved. But in some other cases the displaced thermal plant could be partially or totaly coincide with the second hydro peaking block. In such occasion the next displacement would be needed, following the same logic as before. The energy generated by the thermal plant in the presence of pumped storage plant generation and the two hydro peaking blocks can be composed of three parts as shown in Fig. 2.

After the energy calculation it is possible to form a complete loading order list of plant containing energy produced in the system without the pumped storage plant energy, that could be replaced by the pumped storage plant and energy available for pumping purposes at every plant.

The optimal allocation procedure is essentially a search for two power levels which define the pumped storage operation. In a step by - step procedure, sumining up plant by plant (pumping from the bottom, generating from the top) the largest amount of energy available for pumped storage operation can be determined.

In the procedure several cases are possible. First, the available energy may not be sufficient even for minimum pumped storage operation: for the pumped storage plant as the last plant in the loading order. The second possibility is as follow: the comparison of energies in the list is done on a plant basis, so two amounts of energy compared will generaly not be equal; for generation either all available pumped energy or only the necessary pumped energy may be used, energy not needed should not be pumped. This fact makes the difference between the list mentioned above and the final accounting of produced energy by each thermal plant. As a result of the pumped storage optimal allocation the maximum amount of energy which may be economically transfered in the period considered will be known. This amount which is the optimum generating capability of the pumped storage plant, should be compared during the whole procedure of simulation with the reservoir limitation. This limitation should not be an active factor for the properly designed pumped storage plant. Neverthelese, the chronological diagram for the reservoir level could be established and checked for overflowing or running dry. The final accounting of pumped storage operation in a power system generating diagram is shown in Fig. 3.

Optimization of the Long Term Storage

In the procedure presented the available energy for pumping in a period considered have to be used in the same period. The procedure does not take into account the possiblity of storing energy within one period in order to use it in an other subsequent period so to optimize the generation from pumped storage.

The maximum available pumping energy can be calculated for each period. The available pumping energy may be larger than possible generating energy. But, in the general case it is possible to find such sequence of the energy generated by pumped storage in each period giving the minimum total cost. The problem can be solved by means of dynamic programming. The maximum feasible energy generated in a period can be subdivided into a certain number of energy intervals each one corresponding to an amount of energy which could be used in a period. To each amount of energy a cost value is assigned. The optimal sequence of energy generated in all period will give the minimum total cost. Only difference from the already presented simulation procedure is that this optimization procedure replace the final account procedure in the simulation process.

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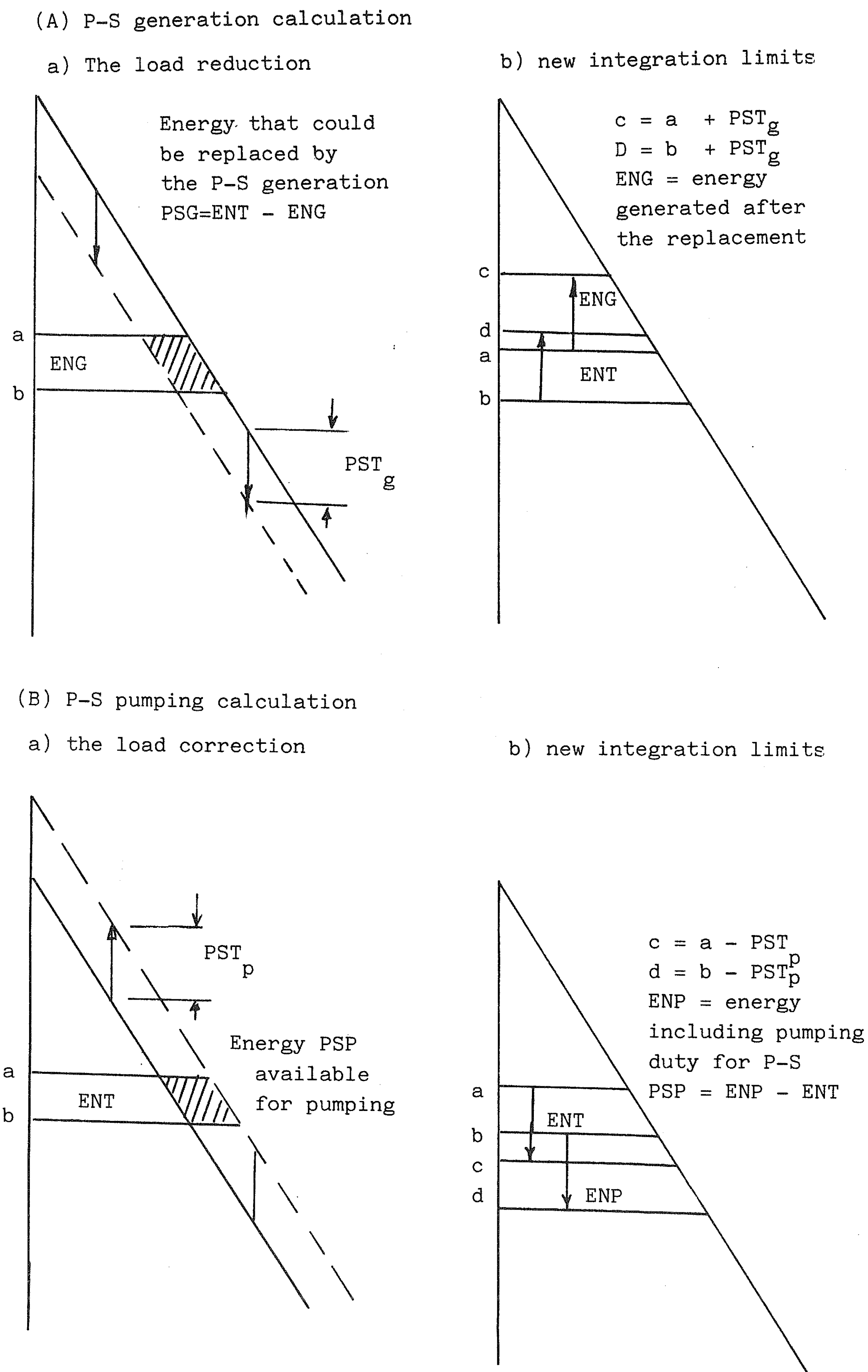
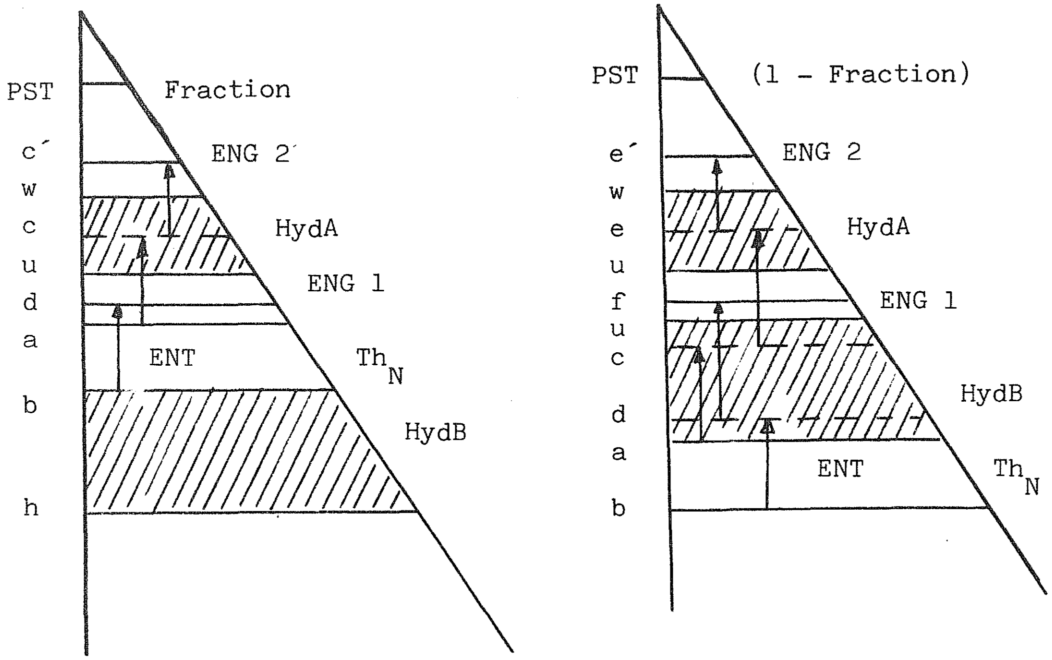
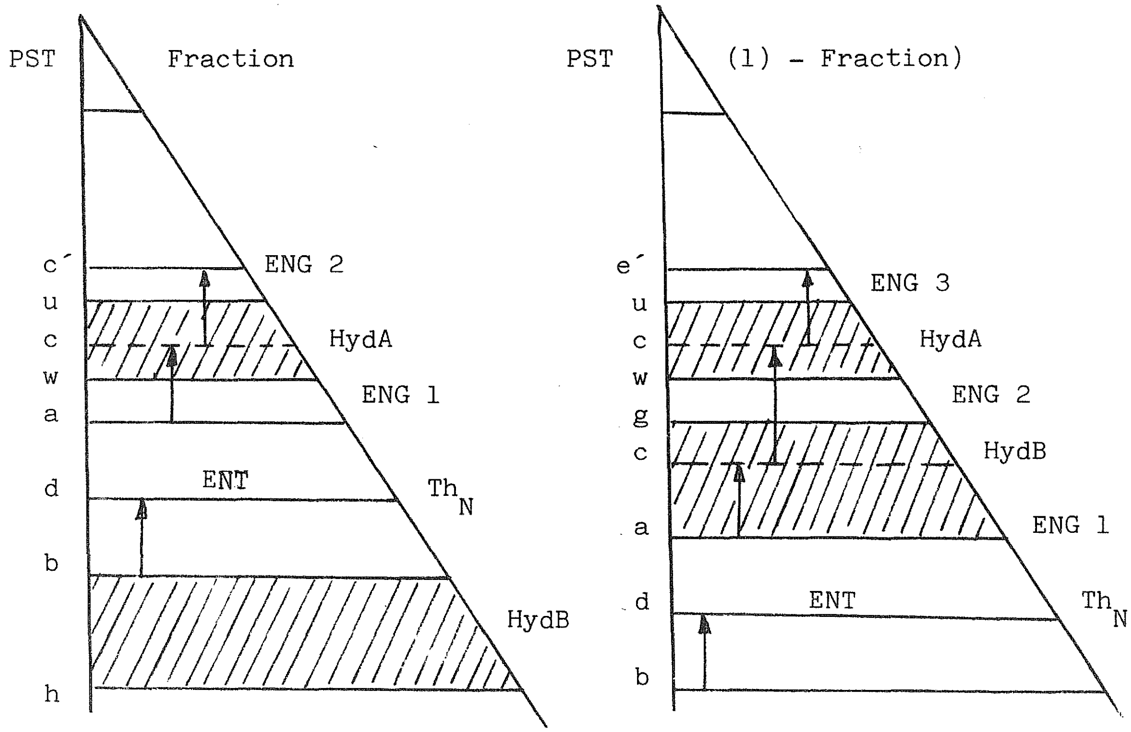


Figure 1. The P-S operation affecting a thermal plant production.



Case: PST_g capacity larger than Th_N capacity



Case: PST_g capacity less than Th_N capacity

Figure 2. Calculation of possible P-S generation, fractional case with two hydro peaking blocks.

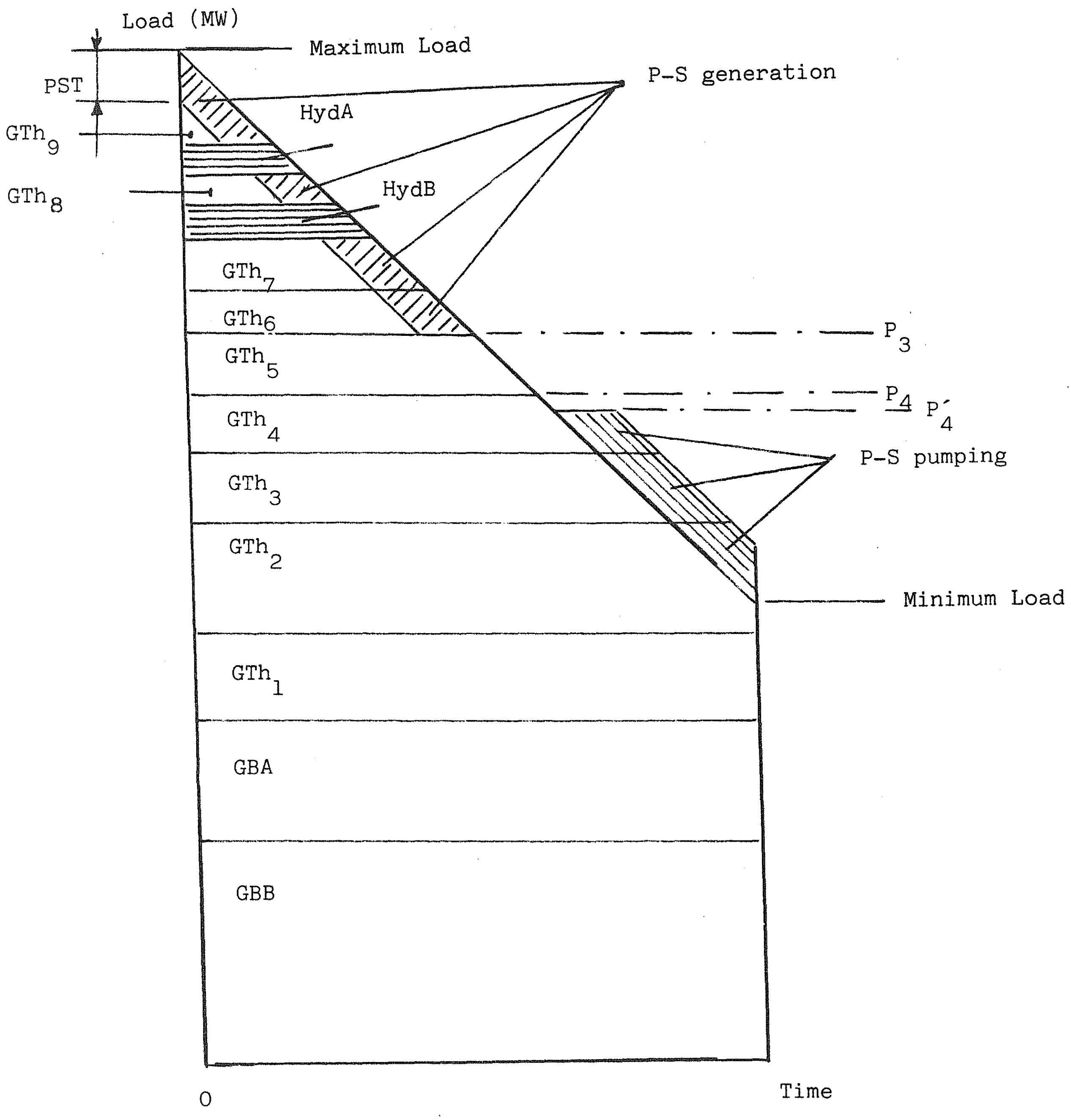


Figure 3. The final account of P-S operation in a power system generating diagram.

Application of the Cumulant Method in WASP-II

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Abstract

This paper describes the application of the cumulant method in WASP-II and related modifications. The Wien Automatic System Planning Package is designed to find optimal generation expansion strategy for an electric utility. Originally, WASP was designed and developed by R. Taber Jenkins of Tennessee Valley Authority. Later versions were developed by David S. Joy (Oak Ridge National Laboratory) and Peter Heinrich (International Atomic Energy Agency). WASP has gained wide acceptance in the electric utility industry. In WASP, production costing is done by probabilistic simulation and optimization is done by dynamic programming. The package consists of six interrelated modules which can be run independently or sequentially. This paper describes a modification of WASP for faster computation speed by introduction of cumulants to represent the equivalent load duration curve. By applying the cumulants, it becomes possible to treat multiple load duration curves in a period for better representation of pumped storage power plants.

Introduction

Each year Korea Electric Power Corporation (KEPCO) has to build new generating facilities to meet the demand and to replace old equipment. It is necessary to decide between various possible electricity generating techniques so as to combine them in the best possible manner. The problem of investment planning consists of determining, among all the possible programs, the one capable of meeting the demand for electricity at the least cost. The traditional method of comparing the economics of nuclear and conventional plant has been to calculate generating cost for each type of plant using capital and fuel cost data along with an assumed plant factor and cost of money. This approach was adequate until recent years because the choice of generating equipment available to electrical utility was fairly limited. This method of determining an expansion plan now appears to be inadequate for a number of reasons. Therefore, KEPCO introduced WASP from International Atomic Energy Agency (IAEA) in 1977 for long-term generation expansion planning. Operating experience with WASP shows that it is a fairly good model for the Korean system. Firstly, the probabilistic simulation technique is suitable for simulating the operation of the generating system dominant in thermal power plants like the Korean power system. Secondly, the optimal solution of WASP is an integral multiple of each type of candidate plant. Therefore, planning engineers can easily make an engineering analysis in a suitable form for the planning process. Unfortunately, the computation time has been a big problem in KEPCO's use and, therefore, to reduce the run time, WASP was modified with cumulants for faster convolution and deconvolution. In this paper, the concepts of cumulants will be introduced first, followed by a description of the WASP modifications.

Equivalent Load Defined

In the application of the cumulant method, the equivalent load consists of a statistical description of consumer demand (load) plus forced outages of plants (outage) attempting to deliver electrical energy. Through using the cumulant method, a representation of equivalent load is obtained from individual representation of load level and capacity on outage. Symbolically speaking,

$$L_e = L + \sum_i L_{oi} \tag{1}$$

where L_e = equivalent load

L = random system load

L_{oi} = random outage level of ith unit

A unit can be modeled either as capacity with random outage or as a fictitious unit that is 100-percent reliable with fictitious load whose availability is equal to the forced outage rate of the actual unit. Equation (1) has used the second concept.

Moments and Cumulants Defined

Moments are expected values of probabilistic values (or functions of these variables). Cumulants are functions of moments. For example, consider a random variable x, having a probability density function (pdf) f(x). The ith moment about a constant, c, is defined as:

$$\begin{aligned} E\{(x-c)^i\} &= \sum(x_i - c)^i f(x_i) \qquad \text{(discrete)} \\ &= \int (x-c)^i f(x)\,dx \qquad \text{(continuous)} \end{aligned} \tag{2}$$

The cumulants of a distribution are defined in terms of the first moment about the origin (the mean) and the higher moments about the mean. For the random variable x having the pdf f(x), the expected (mean) value of x is:

$$\bar{x} = E(x) = \Sigma x_i f(x_i) \quad \text{(discrete)} \qquad (3)$$
$$= \int x f(x)\,dx \quad \text{(continuous)}$$

Higher moments about the mean, $\bar{x}$, are calculated:

$$x_{mi} = E\{(x-\bar{x})^i\} = \Sigma(x - \bar{x})^i f(x_i) \quad \text{(discrete)} \qquad (4)$$
$$= \int (x-\bar{x})^i f(x)\,dx \quad \text{(continuous)}$$

where x_{mi} is the ith moment about the mean.

The first six cumulants are defined as:

$$X_{k1} = \bar{x} \quad \text{(mean)}$$
$$X_{k2} = x_{m2} \quad \text{(variance, i.e., } \sigma^2\text{)}$$
$$X_{k3} = x_{m3}, \quad X_{k4} = x_{m4} - 3(x_{m2})^2 \qquad (5)$$
$$X_{k5} = x_{m5} - 10(x_{m2})(x_{m3})$$
$$X_{k6} = x_{m6} - 15(x_{m2})(x_{m4}) - 10(x_{m3})^2$$

The above relations will be derived later. In essence, the higher cumulants, X_{k3} through X_{k6}, of a distribution with pdf f(x), measure the departure of f(x) from a normal (Gaussian) distribution having mean X_{k1} and variance X_{k2}.

Load Cumulants

Load cumulants can be derived from a probability density function for loads which are either continuous or discrete. In the modified LOADSY program, load cumulants are obtained from forecasted hourly loads. The coefficients of fifth order polynomial for load duration curves can be determined by reading the coefficients directly or can be determined automatically by regressing the historical load duration data and by constraining the regression so that the demand forecast of peak load, base load, and total generation are satisfied by the fitted curve. For this purpose, a program developed by Roderick Thompson (Supply Office, California Energy Resources Conservation and Development Commission) (reference 6) was incorporated into the LOADSY program. With the given load duration curve, the following steps describe the process to determine the load cumulants for a T-hour period, each hour having load $L \cdot f(x)$.

Step 1. Calculate the mean

$$\bar{x} = \left(\sum_{i=1}^{T} L \cdot f(x_i) \right) / T \tag{6}$$

where L = period's peak load

f(x) = fifth order polynomial of load duration curve

T = number of hours in a period

Step 2. Calculate the higher moments about the mean (central moment)

$$\begin{aligned} x_{m2} &= \sum_{i=1}^{T} (L \cdot f(x_i) - \bar{x})^2 / T = \sigma^2 \quad \text{(variance)} \\ &\vdots \\ x_{m6} &= \sum_{i=1}^{T} (L \cdot f(x_i) - \bar{x})^6 / T \end{aligned} \tag{7}$$

Step 3. Calculate the load cumulants using equations (5).

<u>Supply System (Forced Outage) Cumulants</u>

The outage cumulants associated with generating unit forced outages are generally derived from discrete unit outage distributions. Consider the following example of a 100-MW unit with 80-percent availability:

Outage (MW)	0	100
Probability	0.8	0.2

The first two outage cumulants (G_{k1} and G_{k2}) are calculated as follows:

$$\begin{aligned} \bar{x} &= (0)0.8 + (100)0.2 = 20 \\ x_{m2} &= (0-20)^2 0.8 + (100-20)^2 0.2 = 320 + 1280 = 1600 \\ G_{k1} &= \bar{x} = 20 \\ G_{k2} &= x_{m2} = 1600 \end{aligned} \tag{8}$$

Higher order outage moments and outage cumulants are calculated analogously using equations (4) and (5).

This procedure is used to calculate the outage moments for every type of unit in the FIXSYS (fixed system description program) and VARSYS (candidate system description program). Representation of partial outages is not considered in this modification, but is a straightforward extension as in reference (13).

Calculation of the Equivalent Load Curve

Probabilistic simulation requires two basic assumptions regarding independence of events, namely:

1. Outage occurrances are independent of the load.
2. Outage occurrances are independent of other outages.

When these assumptions are true, it is possible to make a statement that seems really startling to users of other algorithms for performing probabilistic simulation. This statement is that the convolution process is merely the addition of cumulants, or more formally:

> The cumulants of the sum of independent random variables are equal to the sum of the cumulants of those random variables.

Since we are treating load and outage as random variables, and since equivalent load is the sum of load and all outages up to the point of interest on the partial or complete equivalent load curve, convolution of forced outages into the equivalent load curve consists of simply adding the appropriate outage cumulants, order for order, to the cumulants of the load or partial equivalent load curve. The startling property of this operation is that it is equivalent to the application of the laborious convolution equation:

$$F'(x) = pF(x) + qF(x-C). \tag{9}$$

In WASP-II, equation (9) must be applied to every Fourier coefficient in the subroutines of MERSIM (probabilistic simulation program). Thus, a series with 100 coefficients would require several hundreds of multiplications. With cumulants, convolution becomes an almost trivial operation (addition of cumulants), and deconvolution (subtraction of cumulants) is equally trivial.

The mathematical details of why the cumulants of the sum of the independent random variables are equal to the sum of the cumulants of those random variables will be explained. Given a random variable and distribution function F(x), the mean of the particular function $e^{it\xi}$ will be written

$$\phi(t) = E(e^{it\xi}) = \int_{-\infty}^{\infty} e^{itx} dF(x) \tag{10}$$

where i is the complex operator ($i^2 = -1$).

This is a function of real variable t, and will be called the characteristic function of the variable ξ or of the corresponding distribution, and there is one to one correspondence between distribution and characteristic function. If we differentiate $\phi(t)$ r times,

$$\phi^{(r)}(t) = i^r \int_{-\infty}^{\infty} e^{itx}\, x^r dF(x) \tag{11}$$

And hence, putting t=0

$$m'_r = (-i)^r \left(\frac{d^r\phi(t)}{dt}\right)_{t=0} \tag{12}$$

provided that m'_r exists. If $\phi(t)$ be developed in MacLaurin's series in the neighborhood of t=0, m'_r must be equal to the coefficients of $(it)^r/r!$ in the expansion. Thus, characteristic function is also a moment generating function. Therefore,

$$\begin{aligned}\phi(t) &= 1+m'_1(it)/1! + \ldots m'_r(it)^r/r! + \ldots \\ &= \int_{-\infty}^{\infty} e^{itx}dF(x)\end{aligned} \tag{13}$$

Cumulants are defined by following identity.

$$\ln\phi(t) = k_1(it) + k_2(it)^2/2! + \ldots k_r(it)^r/r! + \ldots \tag{14}$$

Cumulants are the coefficients of $(it)^r/r!$ in $\ln\phi(t)$ if an expansion in power series exists. The addition of the two independent random variables is equivalent to multiplication of two characteristic functions and is equivalent to adding $\ln\phi_1(t)$ and $\ln\phi_2(t)$. This addition is simply adding each of the coefficients (cumulants) in the above equations. This simple rule is the chief reason for introducing cumulants (semi-invariants).

Evaluation of Ordinate of the Equivalent Load Curve

Consider the equivalent load curve, ELC(x), shown in Figure 1.

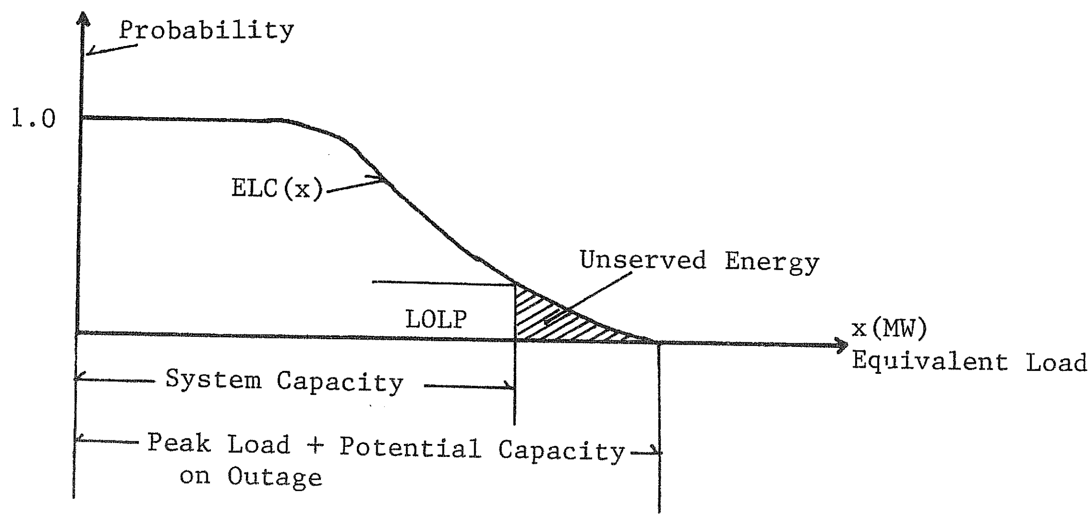

Figure 1

The cumulative probability distribution function typically used by statisticians is developed by integrating the pdf from left to right. However, ELC(x) is obtained by integrating the pdf from right to left. The loss of load probability is the ordinate at x = system capacity. Assuming we have the cumulants of this equivalent load curve, ELC(x), we need then a relationship for calculating the ordinate at x from the cumulants. At this point, the functional relationship between moments and cumulants can be derived.

Subject to the conditions of existence, we have from (13) and (14) formulas

$$1+m_1'(it)+\ldots m_r'(it)^r/r!+\ldots = \exp(k_1(it)/1!+k_2(it)^2/2!+\ldots k_r(it)^r/r!+\ldots)$$

$$= \exp(k_1(it)/1!)\exp(k_2(it)^2/2!)\ldots\exp(k_r(it)^r/r!)\ldots$$

$$= \left(1 + \frac{k_1(it)}{1!} + \frac{k_1^2(it)^2}{2!} +\ldots\right)\left(1 + \frac{k_2(it)^2}{2!} + \frac{1}{2!}\left(\frac{k_2^2(it)^4}{(2!)^2}\right) +\ldots\right)$$

$$\ldots\left(1 + \frac{k_r(it)^r}{r!} + \frac{1}{2!}\left(\frac{k_r(it)^r}{r!}\right)^2 +\ldots\right)\ldots \qquad (15)$$

Picking out the terms in the exponential expressions which, when multiplied together, give a power of $(it)^r$, we have

$$\begin{aligned}
k_1 &= 0\\
k_2 &= m_2\\
k_3 &= m_3\\
k_4 &= m_4 - 3m_2^2\\
k_5 &= m_5 - 10m_3m_2\\
k_6 &= m_6 - 15m_4m_2 - 10m_3^2 + 30m_2^3
\end{aligned} \qquad (16)$$

where m_i is the central moment

To describe the cumulant-ordinate relationship, it is necessary to follow the three steps as follows to calculate equivalent load curve ordinate at a chosen megawatt value = x.

Step 1. Calculate the deviation of the chosen x from the mean i.e., calculate $(x-\bar{x})$ and calculate standard deviation σ as in equation (7).

Step 2. Standardize the deviation from the mean in terms of standard deviation, i.e., calculate $z_1 = (x-\bar{x})/\sigma$. z_1 is commonly referred to as standard variate.

Step 3. Standardize the cumulants X_{k3} to X_{k6} describing ELC(x):

$$\begin{aligned} G_1 &= X_{k3}/\sigma^3 \\ G_2 &= X_{k4}/\sigma^4 \\ G_3 &= X_{k5}/\sigma^5 \\ G_4 &= X_{k6}/\sigma^6 \end{aligned} \tag{17}$$

Next, derivation of Gram-Charlier series Type A will be given. For any frequency function, we may consider an expansion of the form

$$f(x) = C_o N(x) + \frac{C_1}{1!} N^{(1)}(x) + \frac{C_2}{2!} N^{(2)}(x) + \ldots \frac{C_r}{r!} N^{(r)}(x) \ldots \tag{18}$$

where: C_i is constant coefficient and

$N(x) = (1/\sqrt{2\pi})\, e^{-x^2/2}$

$N^{(i)}(x)$ is the ith derivative of N(x).

We define the Tchebycheff-Hermite polynomial $H_r(x)$ by the identity

$$\left(\frac{-d}{dx}\right)^r N(x) = H_r(x)N(x) \tag{19}$$

We have then

$$f(x) = \sum_{j=0}^{\infty} C_j H_j(x)N(x) \tag{20}$$

Multiplying by $H_r(x)$ and integrating from $-\infty$ to ∞, we have in virtue of the orthogonality relationship,

$$C_r = (1/r!) \int_{-\infty}^{\infty} f(x)H_r(x)\,dx \tag{21}$$

In particular, for moments about mean,

$$\begin{aligned} C_0 &= 1 \\ C_1 &= 0 \\ C_2 &= (m_2-1)/2 \\ C_3 &= m_{3/6} \\ C_4 &= (m_4-6m_2+3)/24 \\ C_5 &= (m_5-10m_3)/120 \end{aligned} \tag{22}$$

If f(x) is in standard measure, the series becomes (reference 11),

$$f(x) = N(x)(\frac{1}{6} m_3H_3(x) + \frac{1}{24}(m_4-3)H_4(x) + \ldots) \tag{23}$$

This is the so called Gram-Charlier series of Type A. If expressed in cumulants, this becomes

$$f(x) = N(x) - \frac{G_1}{6} N^{(3)}(x) + (\frac{G_2}{24} N^{(4)}(x) + \frac{G_1^2}{72} N^{(6)}(x))$$
$$-(\frac{G_3}{120} N^{(5)}(x) + \frac{G_1G_2}{144} N^{(7)}(x) + \frac{G_1^{\ 3}}{1296} N^{(9)}(x)) + \ldots \tag{24}$$

where x is a standardized variable representing load plus unit outages with mean zero and variance one. Since most calculations for probabilistic simulations use ELC rather than the frequency distribution in the equation (24), the above equation is integrated and formed into a standardized ELC as follows.

$$F(x)=\int_{-\infty}^{x} f(x)\,dx = \int_{-\infty}^{x} N(x)\,dx - \frac{G_1}{6} N^{(2)}(x) + \frac{G_2}{24} N^{(3)}(x) + \frac{G_1^{\ 2}}{72} N^{(5)}(x)$$
$$-(\frac{G_3}{120} N^{(4)}(x) + \frac{G_1G_2}{144} N^{(6)}(x) + \frac{G_1^3}{1296} N^{(8)}(x)) + \ldots \tag{25}$$

and ELC(x)=1 - F(x)

$$= \int_{x}^{\infty} H(x)\,dx + \frac{G_1}{6} N^{(2)}(x) - (\frac{G_2}{24} N^{(3)}(x) + \frac{G_1^{\ 2}}{72} N^{(5)}(x))$$
$$+ (\frac{G_3}{120} N^{(4)}(x) + \frac{G_1G_2}{144} N^{(6)}(x) + \frac{G_1^{\ 3}}{1296} N^{(8)}(x)) + \ldots \tag{26}$$

The above equation is used repeatedly in probabilistic simulation to calculate unit expected generation.

Evaluation of Integral of Equivalent Load Curve

Now the area below the standardized ELC to the right of point is the integral of the ELC from that point to infinity.

$$E_g(x) = \int_x^{\infty} \int_y^{\infty} N(t)dtdy - \frac{G_1}{6} N^{(1)}(x) + \frac{G_2}{24} N^{(2)}(x) + \frac{G_1^{\,2}}{72} N^{(4)}(x)$$

$$-\left(\frac{G_3}{120} N^{(3)}(x) + \frac{G_1G_2}{144} N^{(5)}(x) + \frac{G_1^{\,3}}{1296} N^{(7)}(x)\right) + \ldots \tag{27}$$

$$= N(x) - x \int_x^{\infty} N(t)dt - \frac{G_1}{6} N^{(1)}(x) + \frac{G_2}{24} N^{(2)}(x) + \frac{G_1^2}{72} N^{(4)}(x)$$

$$-\left(\frac{G_3}{120} N^{(3)}(x) + \frac{G_1G_4}{144} N^{(5)}(x) + \frac{G_1^{\,3}}{1296} N^{(7)}(x)\right) + \ldots \tag{28}$$

The energy in MWh under the tail is given by

$$ENRG = E_g(x)\ (\sigma)\ (T) \tag{29}$$

where σ is the standard deviation in MW (or square root of X_{k2}) and T is the duration of the simulation period in hours. To evaluate the integral of the equivalent load curve, a numerical table is calculated and stored before simulation is done. And then linear interpolation is used to determine the point between the tabulated values. For the normal distribution function and Gaussian function, 1201 elements were stored from -6 standard deviation to +6 standard deviation.

Evaluation of Unit Energies

Determination of unit expected energies are calculated in the following way

$$E_i = P_i \int_A^{A+C_i} ELC_{i-1}(x)dx = P_i \int_A^{\infty} ELC_{i-1}(x)dx - P_i \int_{A+C_i}^{\infty} ELC_{i-1}(x)d(x) \tag{30}$$

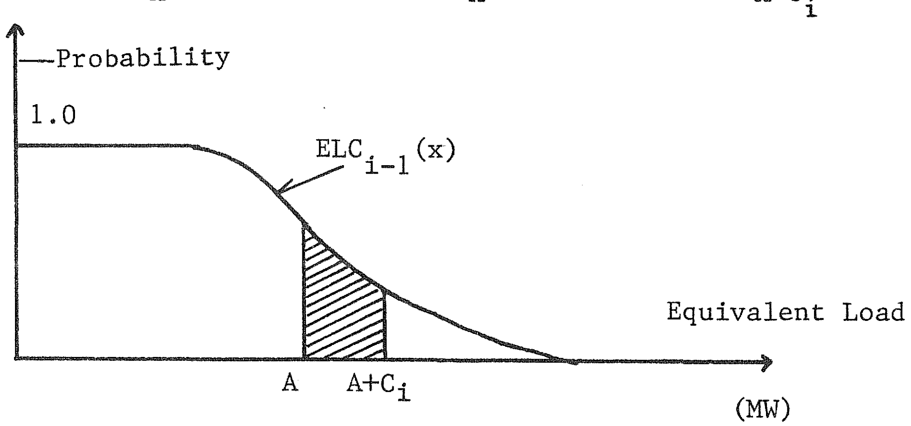

Figure 2

P_i = availability of ith unit

C_i = capacity of ith unit

ELC_{i-1} = the equivalent load curve where the ith and higher units are not convolved.

Method of Adjusting Precalculated Outage Cumulants to Allow for Seasonal Variation

Seasonal capacity variation is handled by use of a constant multiplier to alter the outage cumulants and capacities. In general, consider a unit with the following parameters:

Capacity = C MW

Outage cumulants G_{k1} through G_{k6}

Seasonal multiplier K (a constant)

Then, it follows that the capacity and outage cumulants are adjusted for seasonal capacity variation as follows:

Adjusted capacity = $K \cdot C$

Adjusted $G_{k1} = K \cdot G$

Adjusted $G_{k2} = K^2 \cdot G$

⋮

Adjusted $G_{k6} = K^6 \cdot G$

The appropriate multiplier to adjust each cumulant is simply the constant K raised to the order of the cumulant.

Situations Where Care Must Be Exercised

There are several situations that make the results of cumulant simulations of questionable accuracy. However, most of these situations did not occur on Korea's power systems.

The situations which may generate problems include:

1. A small number of units on the power system, usually less than 10.
2. A power system with a large number of small units and one or two units very much larger in size (units larger than 10 percent of capacity).
3. Very low forced outage rate.

The inaccuracies stem from the fact that the cumulant method is based on a normal distribution with correction factors. The utility of these correction factors becomes limited when the distribution radically departs from the normal distribution. Any condition, such as very low outage rates, which seriously distorts the normal distribution, will make the results questionable.

Results of Modification of WASP-II

In the use of Fourier series representation which is periodic, the period was chosen equal to twice the peak load plus minimum load. When a unit of less-than-perfect reliability is convolved into the equivalent load curve, the peak end of the curve is increased (moved to the right) by the capacity of the unit. It is possible for this point to intrude upon nonzero values of the function in the succeeding period. Function values and integrals where such intrusion has taken place are erroneous. The condition arises on utilities with extremely low minimum loads.

By applying the cumulant method, no periodicity is assumed and these difficulties are avoided. But when applying cumulants with low minimum loads, attention should be paid to the case where there are less than 10 units loaded in merit order below the minimum load. In this case, unit energy generation may be incorrect.

As explained previously, LOADSY (load description program of WASP) was modified so that coefficients of the fifth order polynomial and cumulants are generated automatically. The generation of the fifth order polynomial coefficients uses the regression method described in reference (6). In FIXSYS and VARSYS, outage cumulants are generated for each generating unit. The CONGEN module was modified to calculate reliability of each configuration by Gram-Charlier series Type A. The MERSIM program was extensively modified. Expected energy generation and LOLP after maintenance are calculated by cumulants and Gram-Charlier series Type A. When the LOLP calculated by Fourier series is very close to zero, the LOLP calculated by cumulants sometimes showed a negative value. This is suppressed to zero. Using cumulants with six terms, the production cost calculated is shown to have a difference of about 1/100 percent from the Fourier series calculations using 50 sine terms and 50 cosine terms. Overall computation time is three times faster than the Fourier method with 20 sine terms and 20 cosine terms. This was tested for 6000-MW load and installed capacity of 9500 MW with 12 periods a year and 3 hydro conditions. Because of the increased computation speed, MERSIM was also modified to treat multiple load duration curves in a period. In this case operating cost is the weighted sum of the operating cost calculated with each component load duration curve and system reliability is the weighted average of the LOLP of each component load duration curve. This will permit a better representation of energy storage devices which have different cycle time from the simulation period.

In the DYNPRO (dynamic optimization module), end effects are compensated by estimating the salvage value at the end of the study horizon. An additional end-of-study credit option has been made available to compensate for unused service life of plants when the study ends. In keeping with engineering economic principles, a plant which ends its service life is rebuilt and its discounted reconstruction costs are added to the one-time lump sum cost. For this option, the demand forecast and operating condition are assumed to repeat themselves indefinitely after the study horizon and their discounted operating costs are added to the objective function. The user can choose one of the two options.

With the modifications to use the cumulant method described above, WASP-II shows great promise as a generation expansion planning tool. The substantial reduction in execution time makes studies far less expensive.

Acknowledgement

The author has extensively utilized the research in application of cumulants to probabilistic simulation conducted at the Tennessee Valley Authority.

The author extends his sincere gratitude to R. Taber Jenkins and J. P. Stremel of Tennessee Valley Authority for their continued support and encouragement. Also, the author has received help and support from many people in Korea Electric Power Corporation in the course of preparation of this paper.

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A METHOD TO INCORPORATE THE FORCED OUTAGE EFFECT INTO THE BREAK-EVEN APPROACH FOR ELECTRIC GENERATING SYSTEM PLANNING

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Introduction

The present paper [1] describes a new method to optimize a mix of expansion and existing generating units. This method proposes a way of incorporating the effect of forced outage of generating units into the break-even analysis technique. In the past, the only way to incorporate the forced outage effect into the break-even method was by reducing the capacity of a generating unit by the forced outage rate. In the present approach the probabilistic simulation technique is combined with the traditional break-even analysis so that the variable cost of generation by each unit includes the forced outage effects of other units.

The need for this research was felt because the current computer models in use to analyze the electric utility system problems are large and expensive to run on a computer.

Background

In the past, the break-even analysis had been used for a quicker analysis whenever necessary. Break-even analysis as used traditionally is described below.

To illustrate the break-even analysis, we will assume that (i) the capital cost per unit capacity installed is constant for any given unit regardless of its size, (ii) the operating cost per unit energy output (MWH) is constant for all output levels, and (iii) the capital and operating cost are related in such a manner that the generating unit having highest capital cost has the lowest operating cost, and the unit having the lowest capital cost has the highest operating cost. The units having lower operating cost are loaded first. This order of loading is termed as merit order. By using break-even analysis of capital and operating cost of a pair of competing units, the optimal number of operating hours of a particular unit is determined, from operating hours installed capacity of that particular unit is determined.

If we consider three units as shown in figures 1a and 1b, then it can be shown that:

$$t_1 = \frac{F_1 - F_2}{V_2 - V_1}$$

*This work was done by author at The Ohio State University.

where F_1, F_2 are capital costs for the time period T of unit 1 and 2 respectively in $\frac{\$}{MW}$

V_1, V_2 are operating costs of unit 1 and 2 respectively in $\frac{\$}{MWH}$

t_1 is optimal operating duration of unit 1 in hours.

T is the time period considered for analysis.

Once the optimal duration for operating a particular unit is known, the optimal installed capacity is obtained from the load duration curve.

The above model ignores the forced outage effect. So it fails to describe accurately the system performance at peak hours.

Other researchers such as Jenkins, et al.[2] have taken into account the forced outage effects by reducing the capacity of generating units by a few percent. The method of reducing the capacity of generating units by a few percent is simple but not an accurate model to represent the probabilistic nature of forced outage of generating units.

Modeling Method

The computer model developed uses the concept of screening curve to eliminate those expansion units which are not economical to operate. The method to incorporate the probabilistic aspect of the forced outage into the break-even approach for a mix of existing and expansion units is described in this section.

Screening Curve

To illustrate the concept of screening curve, let us consider four generating units: 1, 2, 3 and 4 as shown in Figure (2a and 2b). The pair of competing units are, 12, 23 and 34 and their corresponding intersection points are t_{12}, t_{23} and t_{34}. By connecting these intersection points with points A and B in the following order, $At_{12}t_{23}t_{34}B$, a curve in the shape of a loop is obtained which is not convex in nature. If unit 3 is not considered then the new pair of competing units are 12 and 24 and by joining the intersection points t_{12} and t_{24} with points A and B, a new curve $At_{12}t_{24}B$ is obtained which is convex in nature.

To apply break-even analysis to an array of generating units they should be first, arranged in the merit order and the intersection point of each pair of competing units when joined with other intersection points should follow a convex curve, which is called the screening curve.

Break-Even Analysis to Incorporate Forced Outages

This section explains how the break-even analysis is applied to power generating systems including probabilistic aspect of the forced outage of generating units. Let us again consider three generating units. We can obtain optimal operating duration of each generating unit as explained earlier. A graphical representation is given in figure 3a and 3b. When the intersection

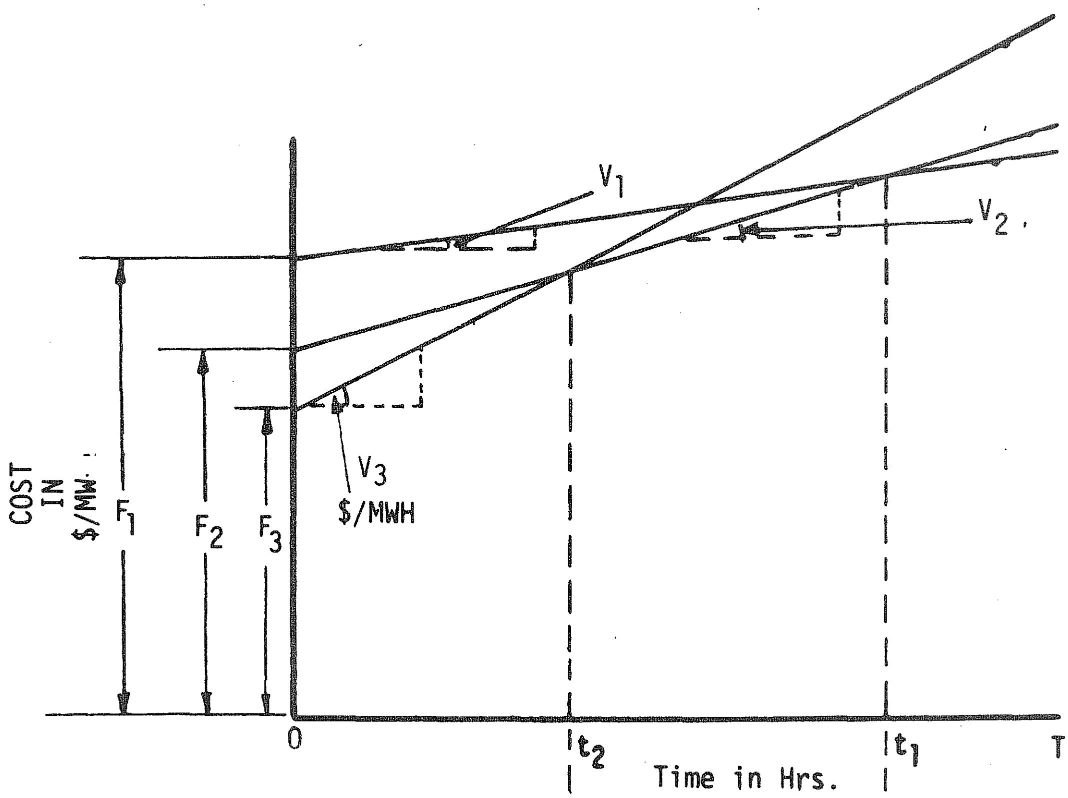

Fig. 1a Cost-Vs-Time Curve for Break-Even Model

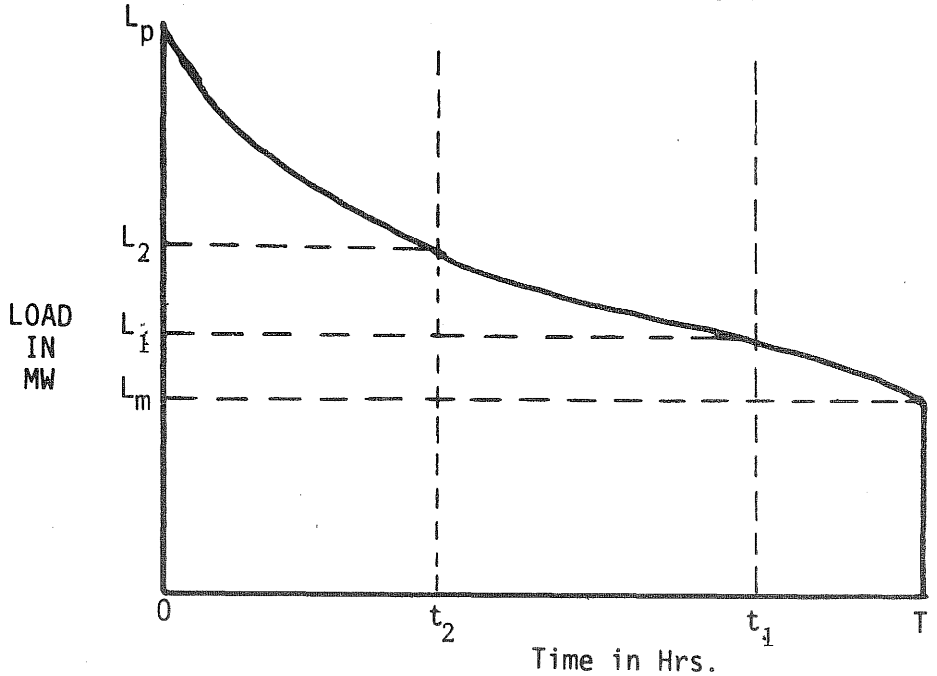

Fig. 1b Load Duration Curve for Break-Even Model

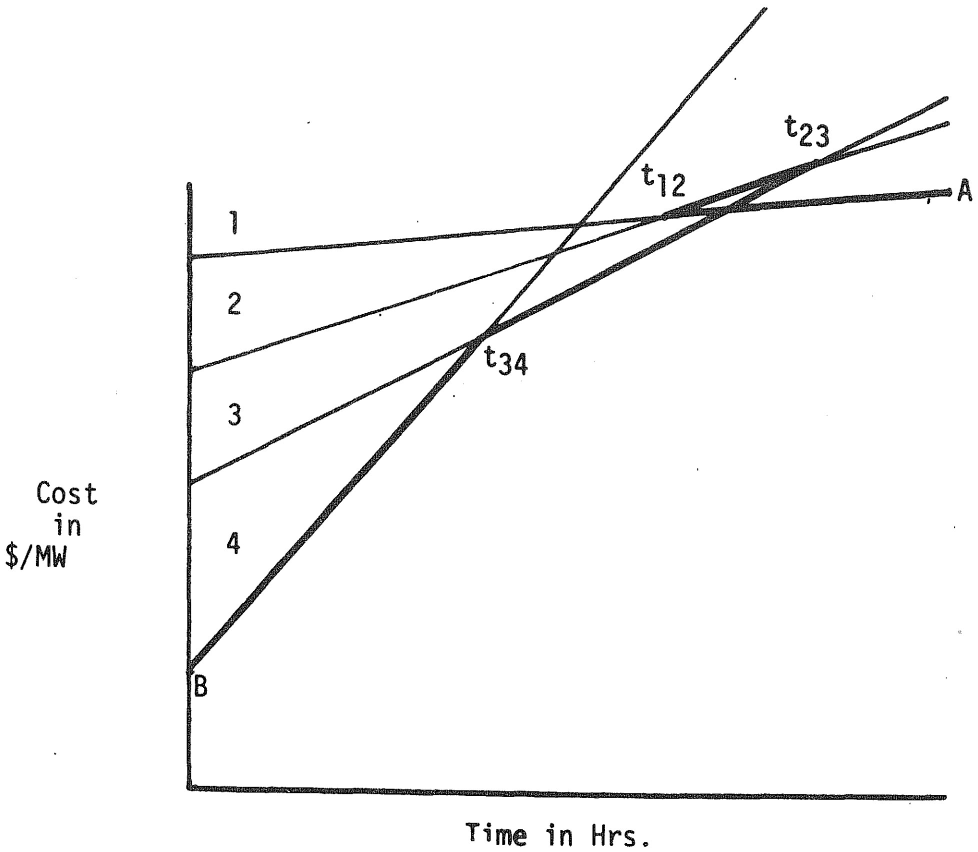

Fig. 2a A Cost-Vs-Time Curve: Four Units

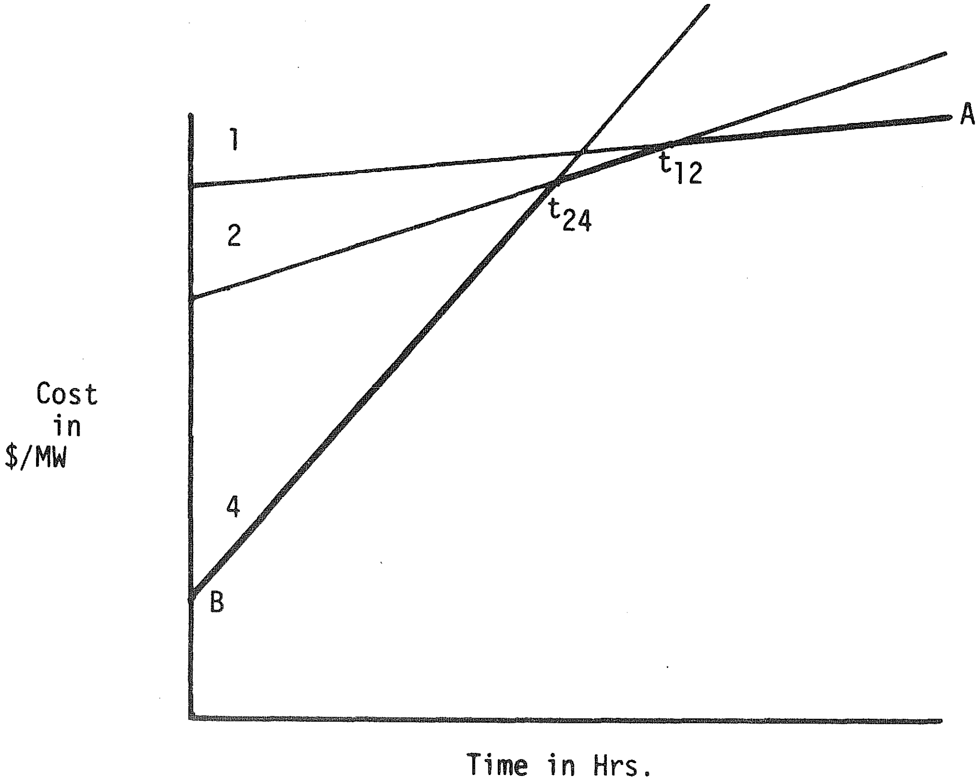

Fig. 2b A Cost-Vs-Time Curve: Three Units

points of a pair of units are projected from figure 3a to figure 3b, then the ordinates of these points from figure 3b give the capacities of the three units for the minimum overall cost. The areas A_1, A_2 and A_3 under the load duration curve (figure 3b) are the energies supplied by each unit. This is true when forced outage is not considered. The cost lines of unit 1 and 2 intersect at the point t_{12}, and those of unit 2 and 3 intersect at t_{23}. The capacity of unit 1 is found from curve $L_0(x)$ by projecting the intersection point t_{12} from figure 3a to figure 3b; the ordinate of this point on figure 3b gives the capacity of unit 1. To apply the above principle for considering the forced outage effect of each unit, the original load duration curve is convolved using the capacity of the first unit and its outage probability to obtain a new load duration curve, $EL_1(x)$. The capacity of unit 2 is found from the curve $EL_1(x)$ by projecting the intersection point t_{23} from figure 3a to figure 3b; the ordinate of this point on figure 3a gives the cumulative capacity up to unit 2. Capacity of unit 2 is $C_2 = K_2 - K_1$, where K_2 is the cumulative capacity of units 1 and 2 and K_1 is the capacity of unit 1.

The capacity of unit 2, as found using the curve $EL_1(x)$, is greater than that using the original load duration curve. This shows that due to the outage probability of unit 1, unit 2 sees more demand of the system. Hence more capacity is required to meet the demand. This is shown in figure 3b. The curve $EL_1(x)$ is convolved again using the capacity of unit 2 and its outage probability to obtain a new load duration curve called $EL_2(x)$. This $EL_2(x)$ is the demand curve that the third unit sees. From the curve, $EL_2(x)$, the capacity of unit 3 is determined, as $C_3 = K_3 - K_2$, where K_3 is the cumulative capacity of units 1, 2 and 3. In this manner the capacity of each unit in a large system can be determined.

Case Study

To verify the validity of the method a computer program was developed and sample cases were run. One such case is presented in this paper. Load and unit data were taken from a typical utility. The system's peak load is of the order of 4770 MW for a duration of 410 hours. The details of expansion unit data are given in Table 1 and that of existing unit data have been omitted from this paper to achieve the required brevity.[1] Out of 30 existing units considered, 10 coal-fired units of 100 MW each, 5 coal-fired units of 70 MW each and 15 gas-fired units of 50 MW each were considered. The original load duration curve is shown in figure 4.

Results

The results of sample case are shown in table 2. It was found that expansion unit N_3 (oil fired) did not follow the screening curve, hence it was not added to the system. The expansion unit N_4 was found to have capacity of 1813.8 MW which represents the aggregate capacity of the 15 gas-fired units. Approximately 15 gas-fired units should be considered to replace expansion unit N_4. Similarly 2 nuclear units should be considered to replace expansion Unit N_2. The total system capacity including outage is found to be 4932 MW for LOLP = 0.02. The loading order of units and the final load duration curve are given in figure 5.

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1. The details of existing data can be found from reference [1].

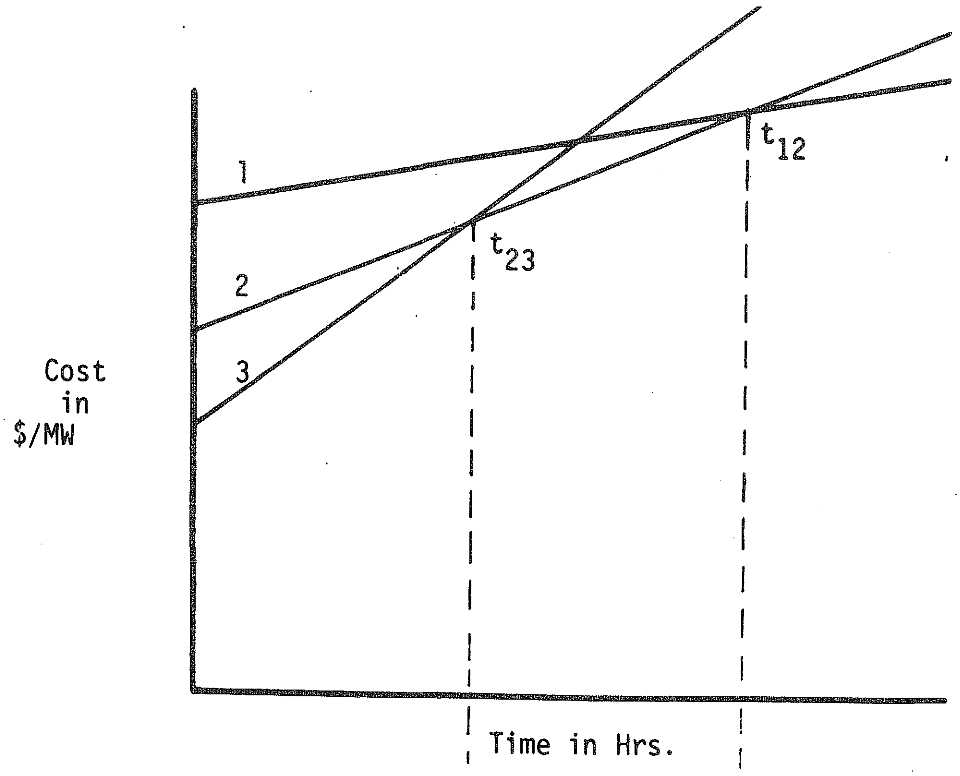

Fig. 3a A Cost-Vs-Time Curve: Model for Incorporating Forced Outages

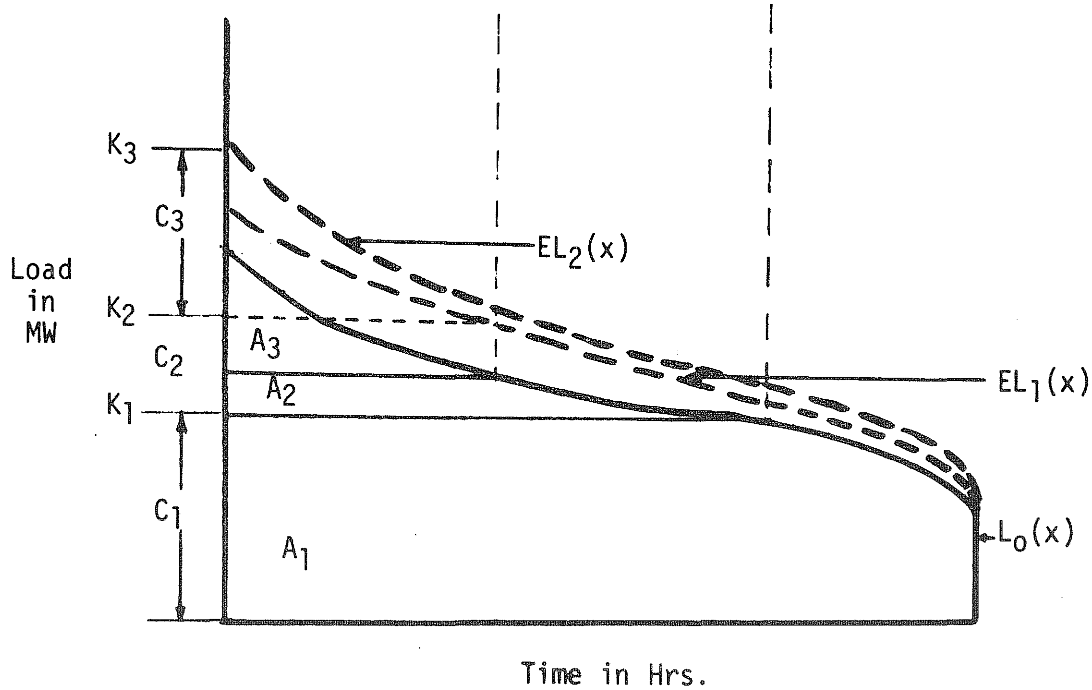

Fig. 3b Load Duration Curve: Model for Incorporating Forced Outages

Tables 1 and 2

TABLE 1 EXPANSION UNIT DATA

Time Period = 410.0 Hrs.

System's Peak Load = 4770.0 MW

Unit Code	Type	Fuel	Capital Cost in \$/MW	Operating Cost in \$/MWH	Forced Outage Probability
N_1		Uranium	187.0×10^2	0.1075×10^2	0.135
N_2		Coal	150.0×10^2	0.2610×10^2	0.120
N_3		Oil	110.0×10^2	0.6480×10^2	0.090
N_4		Gas	47.0×10^2	1.0915×10^2	0.020

TABLE 2 RESULTS OF EXPANSION UNITS: LOLP = 0.02

Unit Type Code	Fuel	Capacity in MW
N_1	Uranium	1443.6
N_2	Coal	82.3
N_3	Oil	Not Added
N_4	Gas	1813.8

Total System Capacity (including Outage) = 4932.0 MW

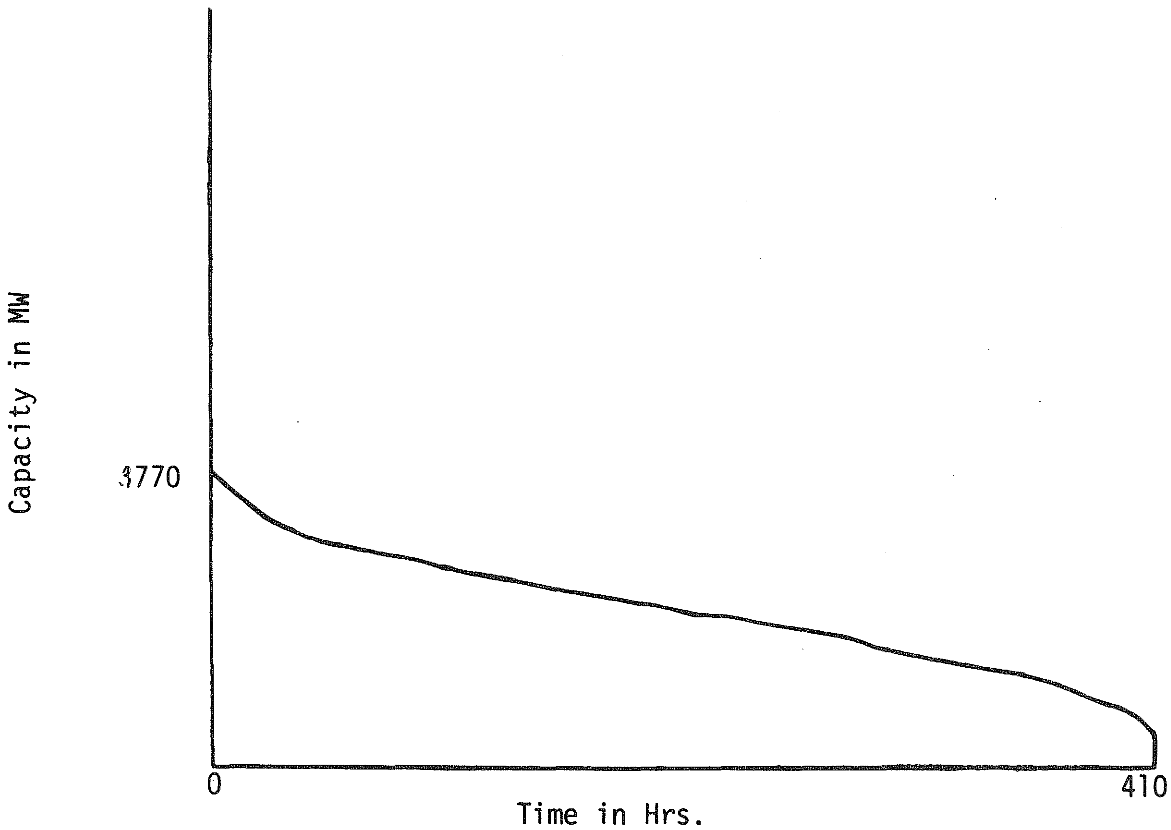

Fig. 4 Original Load Duration Curve

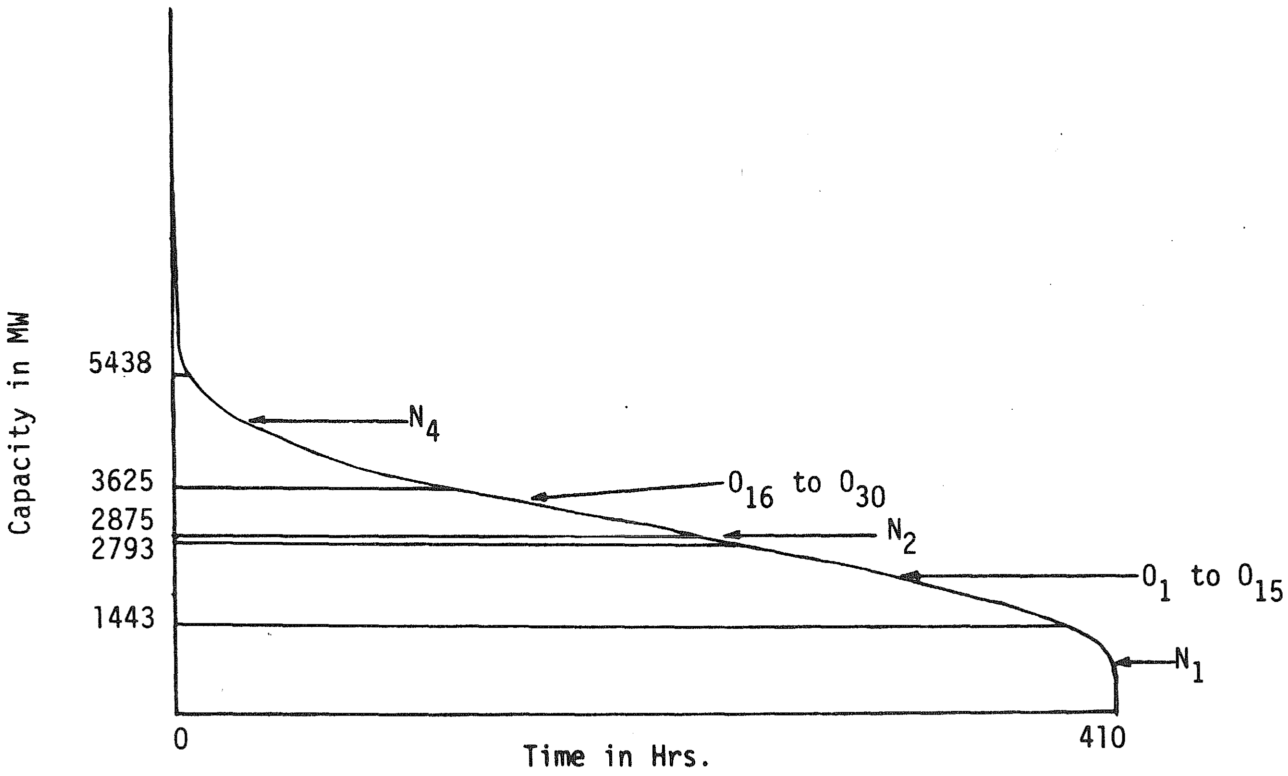

Fig. 5 Final Load Duration Curve: LOLP = 0.02

Conclusion

The results presented in the present paper demonstrate that the break-even analysis can be applied to an electric utility system and the forced outage rates of generating units can be taken into account.

The computer model developed can be used to decide the capacity expansion plan and the most economical way of meeting the system demand for a given system with various reliability and cost constraints.

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PRODUCTION COST OF TWO INTERCONNECTED SYSTEMS UTILIZING THE BIVARIATE GRAM-CHARLIER EXPANSION IMPACT OF LOAD MANAGEMENT AND JOINT OWNERSHIP OF GENERATION

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ABSTRACT

The rationale for system interconnection due to the associated reliability improvement and reserve capacity benefits is well appreciated. The decrease in global production cost is achieved by first committing units with the lowest average incremental cost.

With the increasing recognition that load management could be beneficial to the utility the planner has an added alternative in generation expansion planning in deciding whether to construct a new plant, purchase power from the neighbouring utility or implement a load management scheme.

This paper evaluates the impact of some load management schemes as well as the impact of joint ownership of generation on the production cost of two interconnected systems. The method allows for the correlation of demand to be considered in the probabilistic simulation of system operation. The bivariate Gram-Charlier series is used in the analysis to approximate the probability density function (PDF) of the equivalent demand. This data reduction technique reduces a problem with millions of discrete load states to a problem with a mere hundred of parameters. The process of convolution is performed to obtain the PDF of equivalent demand by properly adding the bivariate cumulants of the PDF of the demand to the PDF of capacity on outage of the generating unit. To take into account joint ownership of generation a model is developed. The paper also gives a description of the methodology.

I. INTRODUCTION

As capital costs of new facilities increase, utilities have been considering other alternatives for meeting peak demand than the construction of new power plants. Load management is one of the alternatives. An annual EPRI-DOE survey [1] shows that over 100 utilities are now involved in a variety of load management programs. Load management may not be as attractive as a new power plant; but recent studies [2-8] show that it is a resource that deserves utility consideration.

Load management is the deliberate control or influencing of customer load in order to alter the pattern of electricity use by time-shifting some of the deferrable loads. The principal objectives of load management are to improve the reliability of service to essential loads, lower the reserve requirements of generation and transmission capacity by shifting electricity use from peak to off-peak periods, improve the system efficiency by reducing the supply provided by relatively inefficient units, reduce the cost/benefit ratio, as well as the average cost of electricity.

With the increasing recognition that load management could be beneficial to the utility the planner has an added alternative in generation expansion planning. He must decide whether to construct a new plant, purchase power from the neighbouring utility or implement a load management scheme.

There are three basic approaches to load management: direct control, customer incentives and energy storage. With direct utility control, the utility uses switching devices to control interruptible customer loads (such as air conditioners) to reduce peak-period demand and deferrable customer loads (such as water heaters, space heating systems, and swimming pool pumps) to shift load to off-peak periods. Direct load control is attractive to utilities because they can plan for specific demand levels. The second approach, customer incentives, such as time of day rates, encourage customers to shift electricity use to off-peak

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periods. However a customer incentive approach may not guarantee the utility a definite demand level, and the utility must plan accordingly. An energy storage approach is the use of electricity during off-peak periods to store energy, usually in the form of heat, for use during peak periods. This approach increases the capacity factor of less costly units.

In this paper firstly a direct approach of load management is considered. For two interconnected systems, the demand of one system, which has higher average incremental cost units, is reduced during a fixed time period of the day. The production costs are evaluated for different tie line capacities. Studies are made by reducing the demand of both systems simultaneously for the same period of the day and the production costs are evaluated. The technique of reducing the demand whenever it exceeds an specific demand level is applied to the system which has the higher average incremental cost units to study the effect on production costs.

Secondly, an energy storage scheme of load management is applied and production costs are evaluated for different tie line capacities.

Lastly, the effect of a jointly owned generating unit on the production cost of individual systems as well as on the global production cost is also analyzed in this paper. The jointly owned generating unit is properly modeled to take into account the export from one system's share to meet the demand of the other system.

The method utilizes the bivariate Gram-Charlier expansion and the joint probability density function of demands to evaluate the production cost. This allows for load correlation to be taken into account. The loading order is decided by considering the average incremental cost of all the available units in the two systems. The decision on the amount of export from one system to the other system is made by considering that this export depends on the following basic quantities: the unserved demand of the exporting system, the unserved demand of the importing system, the capacity of the committed unit and the residual tie line capacity of the exporting system.

The procedure as described in this paper does not take into consideration capital cost of plants, load management equipment, transmission lines and other facilities. The utilization of the Gram-Charlier expansion for reliability evaluation has already been described in [9] and the modelling of joint ownership of generation in [10].

II. METHODOLOGY

The joint probability mass function of the two systems' demands is obtained by sampling the demands of the two systems at every hour (sampling may also be done for smaller intervals of time). A probability value is assigned to each sample assuming that the load at each time interval is equally probable. Coincident loads will clearly gives rise to the addition of the corresponding load probabilities.

Merit order of loading

In the interconnected systems the cheaper resources are utilized first for global benefits. In this method the merit order of loading is decided by considering the average incremental cost of all the units of the two systems available for commitment.

Consider that K_x number of units have been committed in system X and K_y number of units have been committed in system Y. For a total m number of units in system X and n number of units in system Y, the average incremental cost of the next unit in the loading order is expressed as

$$\lambda_i = \min(\lambda_{X_k}, \lambda_{Y_l}) \quad ; \quad \begin{matrix} k=1, \ldots, m-K_x \\ l=1, \ldots, n-K_y \end{matrix} \tag{1}$$

where $i = K_x+1$ or K_y+1, depending on what system is being considered and λ_X and λ_Y are the average incremental costs of the units or system X and system Y repectively.

In what follows the system to which the unit is being committed will be referred to as the exporting system and the other system will referred to as the importing system. So in the process of loading a unit any one of the two systems may take the role of exporting system. In the next commitment of a generating unit the same system may take the role of exporting system or the other system may fulfill this role.

Export

Export from one system to the other system depends on several factors. The major factors which affect the transaction between the two systems interconnected on a power pool basis are: the unserved demand of the exporting system, the unserved demand of the importing system, the capacity of the committed unit and the residual tie line capacity of the exporting system. The residual tie line capacity refers to the remaining capacity of the tie line after its utilization by the previous units in the loading procedure. This will become clearer as the methodology unfolds. More details are given in [11]

Consider two interconnected systems; system X and system Y. In what follows system X will be referred to as the exporting system and system Y will be referred to as the importing system. Consider a stage in the loading procedures when (i-1) units have already been committed in system X and j number of units have already been committed in system Y. Consider two random variables (RVs), L_x and L_y, representing the equivalent demand of system X and the equivalent demand of system Y, repectively. The export Z from system X to system Y at any load point may be expressed in terms of the available generation for export R, the residual tie line capacity of the exporting system RTC_x and the unserved demand of the importing system UD_y. Thus

$$Z = \begin{cases} R & \\ RTC_x & \text{if} \quad R \geq RTC_x \\ UD_y & \quad\quad RTC_x > UD_y \end{cases} \tag{2}$$

where R is given as

$$R = C_t^i - L_x \tag{3}$$

and where

$$C_t^i = \sum_{k=1}^{i} C_k \tag{4}$$

in which C_k is the capacity of the committed units.

The unserved demand in system Y, UD_y may be written as

$$UD_y = L_y - C_t^j \tag{5}$$

where

$$C_t^j = \sum_{k=1}^{j} C_k \tag{6}$$

Expected Energy

The export at any load point is taken into account by modifying the load at that point. The modified demand of the exporting system is expressed as

$$L_y^M = L_x + Z \tag{7}$$

The corresponding modified demand of the importing system can be written as

$$L_y^M = L_y - Z \tag{8}$$

Since the amount of increase of demand of the exporting system and the amount of decrease of demand of the importing system is the same the average demand of the global system remains unchanged. That is

$$E(L_x^M + L_y^M) = E(L_x + L_y) \tag{9}$$

The modification of the residual tie line capacities for both the exporting and the importing systems is necessary for the next stage of the loading order. The modified residual tie line capacities at the load load point where export takes place, are obtained by adding and subtracting the export from the existing residual tie line capacities of the exporting and the importing systems, respectively, i.e.

$$RTC_x^M = RTC_x - Z \tag{10}$$

$$RTC_y^M = RTC_y + Z \tag{11}$$

where RTC_x^M and RTC_y^M are the modified residual tie line capacities of the exporting and the importing systems, repectively.

To calculate the energy supplied by the commited unit the unserved energies before and after the convolution of the PDF of outage capacity of the unit with the joint PDF of the equivalent demand are calculated.

The unserved demand of the exporting system before convolution may be expressed in terms of the expected value as follows:

$$E(DNS_{i-}) = \int_{C_t^{i-1}}^{\infty} \int_0^{\infty} (l_x^M - C_t^{i-1}) \; f_{i-1,j} (l_x^M, l_y^M) \; dl_x^M \; dl_y^M \tag{12}$$

where

$$C_t^{i-1} = \sum_{k=1}^{i-1} C_k \tag{13}$$

and $f_{i-1,j} (l_x^M, l_y^M)$ is the joint PDF of the modified demand before commitment of the next unit in the loading order.

Similarly the unserved demand of the exporting system after the convolution of the unit may be expressed as

$$E(DNS_i) = \int_{C_t^i}^{\infty} \int_0^{\infty} (l_x - C_t^i) \; f_{i,j} (l_x, l_y) \; dl_x, \; dl_y \tag{14}$$

where $f_{i,j}(l_x, l_y)$ is the joint PDF of the equivalent demand after the convolution of the PDF of outage capacity of the committed unit.

The expected energy supplied by the committed unit, $E(ES_i)$, is the product of the time period of study and the difference of two expected unserved demands: the expected unserved demand before the convolution of the PDF of outage capacity of the committed unit and the expected unserved demand after the convolution; that is

$$E(ES_i) = T \left[E(DNS_{i-}) - E(DNS_i) \right] \tag{15}$$

where T is the time period of study.

Production Cost

The cost of energy generation supplied by any unit is obtained by simply multiplying the average incremental cost of that unit and the expected energy generated by the same unit, i.e.

$$EC_i = E(ES_i) \; \lambda_i \tag{16}$$

The total production cost of any one system is obtained by summing over the costs of generation of all the generating units in that system. The global production cost may be obtained by adding the production costs of the two individual systems.

The average global cost of generation may be defined as the ratio of the global production cost and the global expected energy generation. If the units are loaded in capacity blocks as in the case when a better simulation of the varying nature of incremental cost is wanted, the procedure as described must be modified accordingly.

III. JOINT OWNERSHIP OF GENERATION

Consider a generating unit of C MW and FOR=q, jointly owned by the two systems; system X and system Y. Consider the share of system as C_1 MW and the share of system Y as C_2 MW such that C_1+C_2 = C MW. This generating unit may be modeled as two separate generating units owned by the two utilities and whose RV of outage capacity is completely correlated. This means that failure of C_1 MW in system X and failure of C_2 MW in system Y occur simultaneously. Similarly the availability of C_1 MW in system X is dependent on the availability of C_2 in system Y. The joint density function of these two random variables is depicted in Figure 1.

In the modelling of a jointly owned generating unit, it may be located inside of any one of the two systems which are interconnected or it may be located outside the two systems as depicted in Figure 2. In the former case, if the jointly owned generating unit is located in system X, the tie line capacity cannot be less than C_2 MW since if the unit is available in system X with capacity C_1 it must also be available in system Y with capacity C_2. For the purpose of this paper and for simplifying purposes the jointly owned unit is modelled as in Figure 2 so that the tie line transfer capacity may be varied from 0 MW onwards. In this model the jointly owned unit may be considered to be located at the boundary of the two systems.

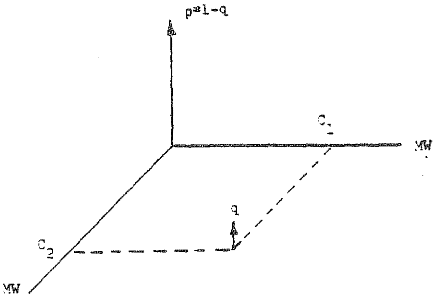

Fig. 1. PDF Outage Capacity of Jointly Owned Generating Unit.

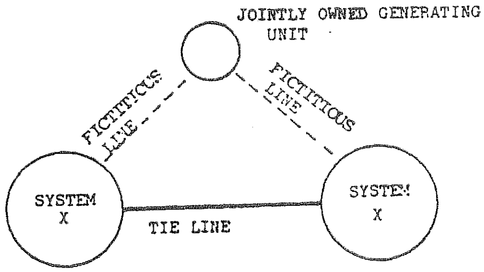

Fig. 2. Jointly Owned Generating Unit Located Outside the Two Systems

Export by Jointly Owned Unit

Since the average incremental cost of the share C_1 MW available in system X and the average incremental cost of the share C_2 MW in system Y are equal and the availability of C_1 MW and C_2 MW in system X and in system Y respectively occur at the same time, the conditions for export supplied by the share from the jointly owned generating unit will be different from that described previously.

The unserved demand of the importing system Y may be obtained by subtracting the total capacities of already committed units in the importing system and the share C_2 MW of the jointly owned generating unit from the corresponding demand of the importing system. So equation (5) is modified to be

$$UD_y = L_y - (C_t^j + C_2) \tag{17}$$

Although seasonal loads are considered in this paper, the method with a jointly owned unit will be exemplified in reference to a single day's load profile.

Consider two interconnected systems; system X and system Y. For the sake of clarity and brevity consider that the demand in system X is 7 MW through the first 12 hours and 10 MW through the next 12 hours. The corresponding demand in system Y is 15 MW for the first 12 hours and 10 MW for the last 13 hours. By sampling the hourly loads of the two systems the joint probability mass function is obtained as depicted in Figure 3. The tie line is limited to 2 MW.

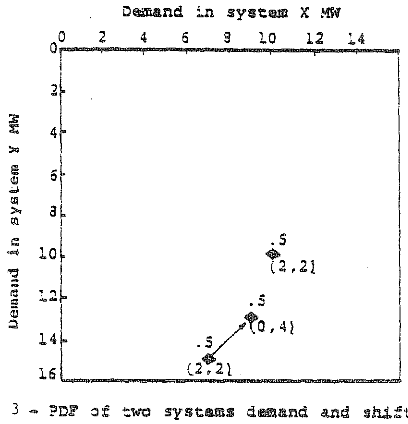

Fig. 3 - PDF of two systems demand and shifting of impulse

Consider a 22 MW jointly owned generating unit with FOR=0.2. The share of system X is 12 MW capacity in either direction. Consider firstly the load point at (7,15). Since the share of system X is 12 MW it is clear that system X can export to system Y. But, although the available generation in system X for export is 5 MW, system X can only export 2 MW to system Y because of tie line capacity restrictions. The modified demand is obtained by adding the export to the demand of system X and subtracting the export from the demand of system Y. So the impulse at (7,15) is shifted to (9,13). The corresponding residual tie line capacity of the system X is reduced to zero. Since the sum of the residual tie line capacities of two systems must always equal to the sum of the actual tie line capacities in either direction (see Ref. 11) the residual tie line capacity of system Y is modified to 4 MW. At the second load point (10,10), both systems have 10 MW demands and the available generation in either system is equal to or greater than 10 MW. So there is no export or import at this load point.

Initially the expected unserved demand of system X is equal to 9x0.5+10x0.5 = 9.5 MW and the expected unserved demand of system Y is equal to 11.5 MW.

Now the PDF of outages of the jointly owned generating unit are convolved with the PDF of the modified demand as shown in Figure 4.

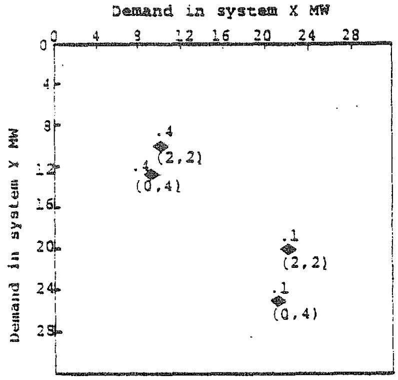

Fig. 4. - PDF of equivalent demand after the convolution of the jointly owned generating unit

Consider the equivalent demand in Figure 4 to recalculate the unserved demands. It is clear that the unserved demand in system X is zero corresponding to loads less than or equal to 12 MW in system X. So the expected unserved demand of system X is (21-12)x0.1 + (22-12)x0.1 = 1.9 MW. Calculating in a similar way, the expected unserved demand of system Y is obtained as 3.5 MW. The expected energy supplied by the share of any one system is the product of the difference of two expected unserved demands of that system before and after the convolution of the jointly owned generating unit and the time period of study. So the expected energy supplied by the share of system X is equal to (9.5-1.9)x24 = 182.4 MWh and the expected energy supplied by the share of system Y is 192 MWh. This result would differ if two independent units would exist in system X and Y.

Since the evaluation as described above is a formidable task even for a small system the method of cumulants is used to account for the random outages of generating units.

V. NUMERICAL EVALUATION

Two interconnected systems are considered one of which is the IEEE Reliability Test System (IEEE-RTS)[12] and the other system is chosen to be the similar to one Canadian electrical utility[13]. Relevant parameters for both systems are given in Appendix 2.

The hourly demand of the IEEE-RTS for the period December to February is considered for the system Y (2160 hours) and the hourly demand of the second system for the same period is considered for system X. System X has an installed capacity of 2621 MW, the seasonal peak load is 1490 MW, the minimum load is 685 MW and the seasonal load factor of 74.33%. System Y has an installed capacity of 3405 MW a peak load is 2850 MW and a base load of 1102 MW. System X has a higher average incremental cost than system Y.

The joint distribution of the demand is approximated by the bivariate Gram-Charlier expansion. The demand plane is then subdivided into a fixed number of grids whose size depends on the size of the system. For the system analyzed in this paper a 50 MW x 50 MW grid structure is utilized. The impulse evaluated for each grid is considered to be situated at the centre of the grid. To each grid a two dimensional array of residual tie line capacities are attached for both systems. The value of this array initially is set equal to the capacity of the tie line. The process of convolution is performed by properly adding the joint cumulants of the PDF of the demand and the cumulants of the PDF of the generating unit.

A binary representation of generating unit's outage capacity is assumed. A multistate model could have been utilized with very little extra computational effort since the cumulants are obtained in a straightforward manner. For the joint unit, the joint cumulants must be calculated in order to add them to the joint cumulants of equivalent demand.

The following studies were performed:

1. Direct load management control of system X by reducing its demand by 10% of the peak demand during the hours of 5 PM to 9 PM.
2. Direct load management control of both systems by reducing both demands by 10% of the peak demands of the respective system during the 5 PM to 9 PM time period.
3. The demand of system X cannot exceed a fixed value, i.e. 1341 MW. If it does it is set to the fixed value.
4. The demand of system X is reduced from 5 PM to 9 PM by 10% and the load level is increased from 11 PM to 12 PM by 10% of the peak demand. This simulates the pumping stage of a pumped storage facility.
5. The IEEE-RTS in system Y has 3 oil fired units of capacity 197 MW with FOR = 0.05 and the average incremental cost = $19.37/MWh. System X has one 200 MW oil fired unit with FOR=0.08 and the average incremental cost = $17/MWh. One of the three 197 MW units of IEEE-RTS system is modified to 200 MW capacity and combined with the 200 MW unit of system X to become one 400 MW jointly owned generating unit. The average incremental cost and FOR of the jointly owned generating unit are assumed to be $17/MWh and 0.08 respectively. Considering a 50% share of the jointly owned generating unit for each system the production costs are evaluated for different tie line capacities. For comparison purposes the production costs are also evaluated considering one 200 MW independent generating unit with FOR=0.08 and average incremental cost = $17/MWh in each system.

Results

The expected energy generation are different when different load management approaches are applied. In Table I the average global production cost for different load management approaches are presented.

Table I - Average cost of energy generation for the global system

Tie line capacity	Average Cost ($/MWh) Base Case i.e. Load management is not applied	Average Cost ($/MWh) Load is reduced from 5 PM to 9 PM in system X only	Average Cost ($/MWh) Load is reduced from 5 PM to 9 PM of both systems	Average Cost ($/MWh) Load is reduced from 5 PM to 9 PM and increased from 11 PM to 12 PM in system X only	Average Cost ($/MWh) Load is reduced whenever it exceeds the specified value
0.0	6.6413	6.4216	6.2378	6.5233	6.6180
100	6.5051	6.3022	6.0958	6.3844	6.4925
200	6.4901	6.3017	6.0872	6.3758	6.4786
300	6.4887	6.2998	6.0851	6.3722	6.4775
400	6.4850	6.2963	6.0813	6.3683	6.4737

In column 2 the average global production cost for the base case (i.e without any load management scheme), for different tie line capacities up to 400 MW are given. Column 3 and 4 show the results with the reduction of load in system X and in both systems, respectively. The results obtained reducing the demand for 5 hours and increasing the same about of demand for 2 hours in system X are presented in column 5. In column 6 the results for different tie line capacities are presented for the demand reduction in system X whenever the load level exceeds 1341 MW. These results are shown graphically in Figure 5 in terms of the percentage of the global production cost at zero MW tie line capacity.

Curves B, E and D clearly indicate that the reduction of demand in system X decreases the possibility of import. In other words the global benefit due to interconnection decreases when the demand is reduced in the system which has higher incremental cost units. But curve C shows that the global benefit due to interconnection increases when demands are reduced in both systems.

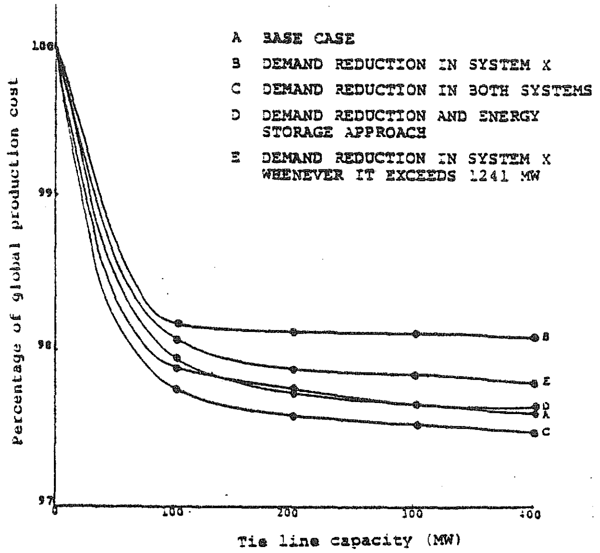

Figure 5 - Global production cost variation with tie line capacity

In Table II the results with and without a jointly owned generating unit are presented. The production cost at zero MW tie line capacity should be equal when the two interconnected systems have a jointly owned generating unit and when they have two independent units of the same capacity. The results of Table 2 show a small difference in the two cases because of the approximation involved by the bivariate Gram-Charlier expansion.

Table II - Production cost for base case and production cost including a jointly owned generating unit

Tie line capacity (MW)	PRODUCTION COST (M$)					
	Base Case			Including the jointly owned generating unit		
	Production cost of system 'X'	Production cost of system 'Y'	Global production cost	Production cost of system 'X'	Production cost of system 'Y'	Global production cost
0.0	10.7039	32.2074	42.9113	10.8360	32.2440	43.0800
100	7.97430	34.0904	42.0647	8.59094	33.9018	42.4927
200	7.59274	34.3448	41.9377	8.33528	34.1357	42.4710
300	7.53743	34.3919	41.9294	8.27413	34.1015	42.4556
400	7.46999	34.4343	41.9044	8.19811	34.2241	42.4222

The production costs without the jointly owned generating unit are referred to as the base case. The global production cost for base case and the global production cost with the jointly owned generating unit for different tie line capacities are shown graphically in Figure 6.

Figure 6 clearly indicates that the decrease of global production cost with the increase of the tie line capacity is less when the two systems have a jointly owned generating unit. Therefore, the possibility of export or import is reduced by the jointly own unit, as could have been predicted.

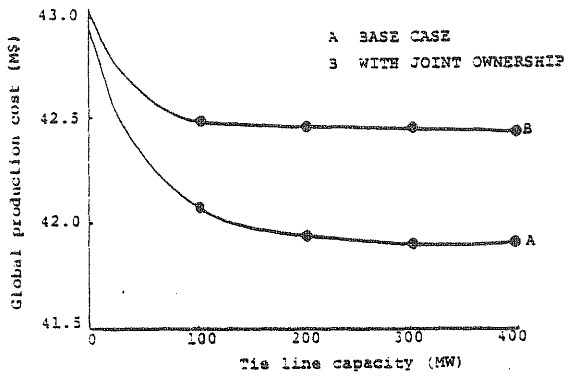

Figure 6 - Global production cost variation with tie line capacity

VII. CONCLUSION

The impact of load management on production cost of two interconnected system including demand correlation is studied. By reducing the demand of the system that has the higher incremental cost units, the decrease of the global production cost due to interconnection is reduced. But if load management is applied to both systems the decrease in the global production cost due to interconnection increases. It is also observed that the decrease of global production cost with the increase of the tie line capacity is less when joint ownership of generation is considered.

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IX. APPENDICES

The bivariate Gram-Charlier expansion is described in Appendix 1. Generation data for systems X and Y are given in Appendix 2.

Appendix 1

From a knowledge of the joint moments or joint cumulants of two random variables a continuous approximating function can be obtained using the bivariate Gram-Charlier expansion.

Consider two dependent RVs X_1 and X_2 with standard deviations σ_1 and σ_2, respectively. In terms of two standardized RVs Z_1 and Z_2 the normal bivariate function may be expressed as

$$\phi(z) = \frac{1}{2\pi\sqrt{R}} e^{-1/2\{a_{11}z_1^2+2a_{12}z_1z_2+a_{22}z_2^2\}} \qquad \text{(A-1)}$$

where R is the correlation determinant given by

$$R = \begin{vmatrix} 1 & \rho \\ \rho & 1 \end{vmatrix} \qquad \text{(A-2)}$$

where

$$\rho = \frac{\mu_{11}}{\sigma_1 \sigma_2} \qquad \text{(A-3)}$$

and

$$A_{ij} = R_{ij}/R \qquad \text{(A-4)}$$

in which R_{ij} is the cofactor of the correlation coefficient ρ_{ij}.

The standardized RVs Z_1 and Z_2 are given as

$$z_1 = \frac{X_1 - E(X_1)}{\sigma_1} \qquad \text{(A-4)}$$

$$z_2 = \frac{X_2 - E(X_2)}{\sigma_2} \qquad \text{(A-5)}$$

The discrete probability distribution function $P_{X_1X_2}(x_1,x_2)$ of the two RVS X_1 and X_2 may be approximated by a continuous function $f_{X_1X_2}(x_1,x_2)$ in terms of the bivariate Gram-Charlier expansion [14,15].

$$f_{X_1X_2}(x_1,x_2) = \frac{1}{\sigma_1 \sigma_2} \sum_{i=0}^{\infty} \sum_{j=0}^{\infty} (-1)^{i+j} D_{ij} H_{ij}\, \phi(z) \qquad \text{(A-6)}$$

where H_{ij} are hermite coefficients which are functions of the coordinates of (x_1,x_2) at any point. The hermite coefficients of order i+j are given by

$$H_{ij} = e^{-1/2g(z)} \cdot \frac{\partial^{i+j}}{\partial z_1^i\, \partial z_2^j} e^{-1/2g(z)} \qquad \text{(A-7)}$$

and

$$g(z) = \sum_{1}^{2} a_{ij} x_i x_j \tag{A-8}$$

The D_{ij} are the coefficients involving the joint cumulants of X_1 and X_2 and given by

$$D_{ij} = \frac{(-1)^{i+j}}{i!\, j!} \int_{-\infty}^{\infty}\int_{-\infty}^{\infty} G_{ij}(z)\, f(z)\, dz_1\, dz_1 \tag{A-9}$$

where $G_{ij}(z)$ is obtained from $H_{ij}(z)$ by replacing the variables a_{ij} by A_{ij}/Δ and ξ_i by z_i. Determinant Δ is given by

$$\Delta = \begin{vmatrix} a_{11} & a_{12} \\ a_{21} & a_{22} \end{vmatrix} \tag{A-9}$$

and A_{ij} are the cofactors of a_{ij}

$$\xi_i = 1/2 \frac{\partial g(z)}{\partial z_1} \tag{A-10}$$

In [11] the D coefficients up to sixth order in terms of joint cumulants are given. The Hermite coefficients H_{ij} are given up to sixth order in [10] and [15].

The process of convolution may be performed by properly adding the cumulants of the PDF of demand and the cumulants of the PDFs of outage capacity of the generating units. In case of a jointly owned generating unit the joint cumulants of the PDF of outage capacity of the unit must be calculated.

Appendix 2

Generation data for system X.

This is a hypothetical system with 19 generating units and an installed capacity of 2621 MW. Relevant data is given in Table A1. The data are similar to those of a Canadian Utility. The loads during the season under study are those from December to February of 1980 [13]. The peak load and the minimum load are 1490 MW and 685 MW respectively. The load factor for this season is found to be 74.33%.

Generation data for system Y

This system resembles the IEEE reliability test system [12]. Relevant data is shown in Table A2. The load during the season under study on this system corresponds to the December to February load of the IEEE reliability test system. In both systems hydro units are loaded as base loaded units.

Table A1 - **Generation data for system X**

Type of Unit	Unit size (MW)	No. of units	FOR %	Average increment cost ($/MWh)
Coal	25	1	8	17.0
Coal	60	1	8	17.0
Coal	200	1	8	17.0
Oil	36	1	7	35.0
Oil	50	1	7	35.0
Oil	100	3	7	35.0
Oil	350	3	9	40.0
Gas	23	1	10	45.0
Hydro	110	3	1	0.0
Hydro	102	3	1	0.0
Hydro	241	1	1	0.0
TOTAL	2621	19		

Table A2 - Generation data for system Y

Type of Unit	Unit size (MW)	No. of units	FOR %	Average incremental cost ($/MWh)
Nuclear	400	2	12	5.592
Coal	155	4	4	11.160
Coal	350	1	8	11.400
Coal	76	4	2	14.382
Oil	197	3	5	19.270
Oil	100	3	4	22.080
Oil	12	5	2	28.558
Oil	20	4	10	37.500
Hydro	50	6	1	0.0
TOTAL	3405	32		

APPLICATION OF PONTRYAGIN'S MAXIMUM PRINCIPLE ON CAPACITY EXPANSION AND COMPARISON WITH STAGE ITERATIVE DYNAMIC PROGRAMMING

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Abstract

An optimization algorithm that uses the discrete form of Pontryagin's maximum principle is proposed for the solution of capacity expansion optimization problems. The proposed algorithm utilizes dynamic programming for the minimization of the stage-wise Hamiltonian. The combined use of Pontryagin's maximum principle and dynamic programming overcomes successfully the difficulties associated with the individual use of either of these optimization methods. Namely, the proposed method requires significantly less memory than dynamic programming and is better than the maximum principle alone, since it is shown to find the global optima for non-convex, non-linear objective functions in the presence of constraints.

1. Introduction

The discrete form of Pontryagin's Maximum Principle (PMP) [1] has been used extensively in the solution of multistage optimal control problems of chemical processes by L. Fan [2], Katz [3], and others [4]. However, it has been shown [5-10] that only the weak form of Pontryagin's maximum principle is applicable in physically staged discrete-time systems and only in cases where the reachable states of the system are convex.

The electric utility capacity expansion optimal control problem does not fulfill the convexity requirement of the discrete maximum principle. However, it will be shown here, that when the maximum principle is combined with Stage Iterative Dynamic Programming (SIPD) [11] the optimal control policy is always obtained for a sufficiently large optimization step.

The only attempt to apply Pontryagin's maximum principle to capacity expansion planning, that the author is aware of, is by Elecricite De France [12]. However, the authors of the EDF paper provide few details and do not show their results.

2. Statement of the Problem

The electric power generating system capacity expansion problem is formulated as an open-ended optimal control problem. The generating system configuration in year t, is described by the state vector $\bar{x}_t$.

$$\bar{x}_t = [x_{k,t}] \tag{1}$$

where $x_{k,t}$ is the number of generating units of plant type k in year t.

The generating system expansion policy in year t, is described by the control vector $\bar{u}_t$.

$$\bar{u}_t = [u_{k,t}] \tag{2}$$

where $u_{k,t}$ is the number of units of plant type k that are added to the system in year t.

The state and control vectors are related through the "system equation"

$$\bar{x}_{t+1} = \bar{h}(\bar{x}_t, \bar{u}_t) \tag{3}$$

which in the capacity expansion problem takes the form

$$\bar{x}_{t+1} = \bar{x}_t + \bar{u}_t \quad , \tag{4}$$

and

$$\bar{x}_o = \bar{x}_{init.} \text{ (given)} \quad . \tag{5}$$

The state and control variables are subject to constraints of the form

$$a_{k,t} \leqslant x_{k,t} \leqslant b_{k,t} \tag{6}$$

$$d_{k,t} \leqslant u_{k,t} \leqslant e_{k,t} \tag{7}$$

where $a_{k,t}$ and $b_{k,t}$ are the lower and upper bounds of units of plant type k in year t

$d_{k,t}$ and $e_{k,t}$ are the lower and upper bounds of units of plant type k that may be added to the system in year t.

The objective of the optimization is to find a series of controls $\overline{u}_o, \overline{u}_1, \overline{u}_2, \ldots, \overline{u}_t, \ldots, u_{T-1}$ that minimize the objective functions $I(\overline{x}_o, T)$, defined as

$$I(\overline{x}_o, T) = \sum_{t=1}^{T-1} g_t(\overline{x}_t, \overline{u}_t) \tag{8}$$

where $g_t(\overline{x}_t, \overline{u}_t)$ represents the discounted costs of investments and generating system operations in year t, and

T is the length of the planning horizon in years.

3. PMP Formulation

Let the state vector of Equation (1) be redefined to have K + 1 elements where $x_{k,t}$ for $k = 1,2,\ldots,K$ are defined as in Equation (1) and

$$x_{K+1,t} = \sum_{i=1}^{t-1} g_i(\overline{x}_i, \overline{u}_i) \quad . \tag{9}$$

The objective function can be written as

$$I(\bar{x}_o, T) = \sum_{k=1}^{K+1} c_k x_{k,T} \tag{10}$$

where c_k are arbitrary constants. If $c_k = 0$ for $k=1,2,\ldots,K$, and $c_{K+1}=1$, then

$$I(\bar{x}_o, T) = x_{K+1,T} \quad . \tag{11}$$

The system adjoint vector, $\bar{z}_t$, is defined, [10], as

$$\bar{z}_t = \frac{\partial \bar{h}_t(\bar{x}_t, \bar{u}_t)}{\partial \bar{x}_t} \bar{z}_{t+1} \quad . \tag{12}$$

In order to minimize $\bar{x}_{K+1}$, the final values of the adjoint vector are set to

$$\bar{z}_{k,T} = 0 \text{ for } k = 1,2,\ldots,K \tag{13}$$

$$\bar{z}_{K+1,T} = 1 \quad . \tag{14}$$

The weak form of Pontryagin's maximum principle states that, [10], in order to minimize the objective function of Equation (11) we must minimize the Hamiltonian H_t for each $t=1,2,\ldots,T$. The Hamiltonian is defined as

$$H_t = \bar{z}_t' \cdot \bar{x}_t \tag{15}$$

where z_t' is the transpose of $\bar{z}_t$.

Equations (12, (13), and (14) give

$$z_{k,t} = z_{k,t+1} + \frac{\partial g_{k,t}}{\partial x_{k,t+1}} \cdot z_{k,t+1} \text{ for } k = 1,2,\ldots,K \tag{16}$$

and

$$z_{K+1,t} = 1 \text{ for } t = 1,2,\ldots,T . \tag{17}$$

Thus, the Hamiltonian can be written as

$$H_t = \sum_{i=1}^{t-1} g_i (\bar{x}_i, \bar{u}_i) + \sum_{k=1}^{K} x_{k,t} z_{k,t} \tag{18}$$

$$H_T = I(\bar{x}_o, T) \quad . \tag{19}$$

Equation (19) shows that minimizing the Hamiltonian will minimize the objective function.

4. Optimization Algorithm

The Hamiltonian will be minimized iteratively. However, since the optimization involves a bounded, physically staged discrete system for which convexity cannot be established [9, 10], Dynamic Programming (DP) will be used in the minimization of the Hamiltonian in the same fashion as DP is used in the minimization of the objective function in the Stage Iterative Dynamic Programming (SIDP) algorithm. [11] The combined Pontryagin Maximum Principle-Dynamic Programming (PMPDP) algorithm consists of the following steps:

Step 1. Set the stage (time) step size, m, to 1.

Step 2. Assume an initial guess for the control vectors, $\bar{u}_t$, t=1, 2, ..., T-1, and denote them with $\bar{u}_t^o$ where the superscript indicates the iteration number n = 0. Calculate the state and adjoint vectors, and the Hamiltonian and denote them with $\bar{x}_t^o$, $\bar{z}_t^o$, and $\bar{H}_t^o$ respectively for t=1, 2, ..., T.

Step 3. Find the optimal controls, $\bar{u}_t^n$, n=1, that minimizes the Hamiltonian H_{t+m}^n by applying dynamic programming between t=1 and t+m, with $\bar{x}_1$ given and $\bar{z}_t = \bar{z}_t^n$, n=o.

Step 4. Repeat finding the optimal controls $\bar{u}_t^n$ that minimize the Hamiltonian H_{t+m}^n for t=2, 3, ..., T-m with $\bar{x}_t^n$ given and $z_t^n = z_t^{n-1}$, where n = 1.

Step 5. If $\bar{u}_t^n = \bar{u}_t^{n-1}$ for t=1, 2, ..., T-1 then u_t^n is the optimal set of controls. If $\bar{u}_t^n \neq \bar{u}_t^{n-1}$ then set $\bar{u}_t^{n-1} = u_t^n$, $\bar{z}_t^{n-1} = z_t^n$ and repeat Steps 3 and 4.

Step 6. If an iteration limit is reached in iterating through Steps 3, 4, and 5, then set the time step m = m+1 and repeat Steps 2 through 5.

Note that the PMPDP algorithm reduces to strict PMP when m=1 and to strict DP when m=T-1.

5. Test Problem Definition

The PMPDP algorithm is applied here to a test optimization problem under various definitions of discrete objective function. In this one-dimensional problem the system equation is assumed to be

$$x_{t+1} = x_t + u_t \tag{20}$$

where x_t and u_t are integers constrained by

$$1 \leq x_t \leq 21 \tag{21}$$

$$-2 \leq u_t \leq 2 \tag{22}$$

The objective function is

$$I = \sum_{t=1}^{T-1} A_t \tag{23}$$

where the different definitions for A_t, as given in Table 1, are used. In all cases listed in Table 1 the objective functions are discrete and nonconvex [11]. The boundary conditions are

$$N = 20,\ X_i = 10,\ \text{and}\ z_{20} = 0 \ .$$

TABLE 1. VARIOUS OBJECTIVE FUNCTIONS FOR THE TEST PROBLEM

	OBJECTIVE FUNCTION $= \sum_{n=1}^{N} A_n$
Case Number	A_n
1	$(x_n-1)^2 + u_n^2$
2	$(x_n-1)^2 - u_n^2$
3	$[(x_n-1)^2 + u_n^2]^{1/2}$
4	$(x_n-1) + u_n$
5	$(x_n-1)^3 + u_n^3$
6	$(x_n-1)^3 - u_n$
7	$(x_n-1) - u_n^3$
8	$x_n^{-2} + (u_n+10)^{-2}$
9	$[x_n^{-2} + (u_n+10)^{-2}]^{1/2}$
10	$x_n^{-1} + (u_n+10)^{-1}$
11	$[x_n^{-1} + (u_n+10)^{-1}]^{1/2}$
12	$x_n^{-3} + (u_n+10)^{-3}$

6. Results and Analysis

Table 2 shows the value of the objective function to which PMPDP converged for each of the case studies, the number of iterations required for convergence, the size of the stage step size required to obtain the optimum objective function, and the value of the optimum objective function that was obtained by applying traditional dynamic programming. It should be noted that in all but two cases (Cases 2 and 7) the optimum objective function was obtained with stage step size m=1, which means that direct application of Pontryagin's maximum principle resulted in finding the optimum objective function. However in Cases 2 and 7, a stage step size m=2 and m=3, respectively, was required to obtain the optimum value of the objective function. In Case 7, although the optimum objective function was obtained with m=3, the optimum set of controls was different from the controls obtained by traditional dynamic programming, indicating that the optimal control policy was not unique.

It should be noted that the stage step size, m, that is necessary to obtain the optimum objective function is not known a priori. However, when the stage step size was increased, the optimum solution was obtained.

Table 3 shows the computer time required to obtain the optimum solution by standard DP and by PMPDP. In all cases except Case 2 and Case 7 the time required by standard DP is greater than the time required by PMPDP. The opposite is true in Cases 2 and 7 where a stage step size greater than 1 was used.

The longer computing time required by PMPDP when $m > 1$, is compensated for by reduced memory requirements when compared to standard DP. The memory requirements are proportional to the stage step size. In dynamic programming the stage step size is equal to 20 in the test problem. The maximum stage step size used by PMPDP in the test problem is 3. Therefore the memory required by PMPDP was smaller than the memory required by standard DP by an order of magnitude.

7. Comparison with SIDP

The PMPDP algorithm proposed in this paper is more suitable for solving the electric utility capacity expansion problem than SIDP [11], because PMPDP does not require a fixed final boundary condition. Therefore PMPDP is directly applicable to the capacity expansion problem.

The objective function definitions of the test problem of this paper are identical to those of the test problem solved by SIDP in Reference [11]. PMPDP found the optimum in smaller number of iterations and with smaller

TABLE 2. OBJECTIVE FUNCTION AND STAGE STEP SIZE REQUIRED FOR CONVERGENCE OF PMPDP FOR THE TEST PROBLEM

Case Number	Minimum Obj.Fn.	Stage Step Size of PMPDP: 1 (PMP) Obj.Fn.	1 (PMP) Iter.	2 Obj.Fn.	2 Iter.	3 Obj.Fn.	3 Iter.
1	251	251	2				
2	213	217	4	213	2		
3	45.477	45.77	2				
4	35	35	2				
5	1781	1781	2				
6	1821	1821	2				
7	44	57	2	54	2	44	2
8	.234	.234	2				
9	2.105	2.105	2				
10	2.849	2.849	2				
11	7.354	7.354	2				
12	.020	.020	2				

TABLE 3. COMPUTER TIME REQUIRED BY DP AND PMPDP TO OBTAIN THE OPTIMAL SOLUTION (SYSTEM SECONDS)

Case Number	Standard DP Time	PMPDP Time	PMPDP Stage Step Size
1	.72	.638	1
2	.711	.799	2
3	.761	.643	1
4	.711	.643	1
5	.731	.639	1
6	.716	.64	1
7	.713	.973	3
8	.763	.644	1
9	.802	.65	1
10	.738	.643	1
11	.79	.644	1
12	.772	.645	1

stage step size than SIDP for the corresponding objective function definition.

Direct comparison of the computer time requirements between the PMPDP and SIDP test problems is not possible because the two programs were developed on different computers. However, since the same DP algorithm was used in both programs, an indirect comparison shows that PMPDP is faster than SIDP. The memory requirements of PMPDP are slightly greater than those of SIDP.

8. Conclusions

The proposed algorithm combines the use of the discrete form of Pontryagin's maximum principle with stage iterative dynamic programming, and is demonstrated to find the optimum solutions for inherently discrete, non-convex objective functions in the presence of state and control vector constraints.

The new algorithm is similar to the stage iterative dynamic programming algorithm in the iterative use of the multiple stage optimization. However, the new algorithm is more suitable for open ended (initial value) optimization problems than the stage iterative dynamic programming algorithm.

The application of the proposed algorithm to electric utility capacity expansion is straightforward.

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THE IMPLEMENTATION AND APPLICATION OF THE WASP-III AT CNEN/BRAZIL

by

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Abstract

At first, this paper describes the main dificulties faced in the implementation of the WASP-III on the Honeywell Bull DPS 6/64 computer at CNEN. After the implementation, tests making use of input data provided by International Atomic Energy Agency - IAEA were performed and comparative results from accomplishment periods of time are presented with the basic characteristics of the computer employed and the modifications carried out to adapt the programm.

Secondly, the WASP-III was applied to middle-sized electric system based upon the Brazilian North/Northeast System. The main purpose of this stage consisted in the analysis of the WASP model applicability in the Brazilian electric systems characterized by the prevailing participation of the large hydroelectric potencials and by the existence of some hydro power plants having great pluriannual reservoirs. Nowadays, the electric system taken into account has 6181 MW installed, being 5641 MW from hydraulic power and 540 MW from thermal sources (oil) to fulfill an energy demand for 22,534 GWh.

1. Introduction

The pioneering utilization of the WASP model, as one of the means for the planning of the expansion of the Brazilian Electric System was achieved during the Electric System Expansion Planning Training Course - Argonne, January to March, 1980 - under sponsorship of IAEA. On that occasion, the WASP-II was applied to the South/Southeast Interconnected System what leads us to the conclusion that the version II, due to its limitation, was not appropriate when applied to the Brazilian systems characterized by the prevailing participation of the large hidroelectric potencials. /1/

2. The Implementation of the WASP-III at CNEN

In 1982, the Brazilian Nuclear Energy Commission - CNEN/Brazil acquired the WASP-III computer package from the International Atomic Energy Agency. Our first task was to load the package on HB - Honeywell Bull, DPS 6/64. A few modifications were needed because the original version of WASP-III is programmed for IBM computer. The main modifications carried out to adapt the WASP-III package and some characteristics of the HB - DPS 6/64 computer are shown in Appendix A.

In order to check the conversion success, tests making use case 39 - IAEA input data were carried ont. The CPU times spent in each modules, during the execution of case 39 - IAEA and case - North/Northeast, are shown as following:

		CPU time (min.)	
modules		Case 39-IAEA	Case North/Northeast
LOADSY		1.26	0.65
FIXSYS		0.55	0.77
VARSYS		0.17	0.28
	RUN 1	1.91	15.98
	RUN 2	6.38	21.39
CONGEN	RUN 3	28.28	28.70
	RUN 4	-	22.93
	RUN 5	-	23.92
	RUN 1	6.71	153.89
	RUN 2	80.63	71.84
MERSIM	RUN 3	452.39	68.34
	RUN 4	-	13.42
	RUN 5	-	10.27
REMERSIM		5.53	9.32
	RUN 1	0.36	42.32
	RUN 2	5.71	43.83
DYNPRO	RUN 3	86.62	78.42
	RUN 4	-	69.31
	RUN 5	-	85.43
REPROBAT		2.10	4.21

After finishing the execution of Case 39 - IAEA, it was clear that we needed larger CPU time for running package, once only Mersim module run (run 3) spent 452.39 minutes compared to 100 minutes CPU time spent by all runs for this case on IBM 3032 computer /4/. The total CPU time required to run case North/Northeast was about 13 hours, what is considered very high.

3. The Application of WASP-III:

3.1 - General Information

In order to analyse the applicability and the viability of WASP-III computer package when used as a tool for long term expansion planning for electric generation system in Brazil, it was applied to the North/Northeast Interconnected System. Some data were estimated due to the lack of more reliable ones and then, the results presented in this study should not be taken as real optimum configuration for the electric system expansion considered.

Figure 1 illustrates the regional distribution of hydro power potencials and some basic information about North and Northeast Regions. This figure makes us believe that Brazilian electric energy requirement would be fulfilled exclusively by the hydric resources until next century, but the regional distribution of such potenciality does not match with the distribution of demand.

For instance, the largest hydro power potencial is located in the North Region (97,800 MW) and the load centers are in the South and Southeast Regions. Nowadays, these two Regions used up almost 90% of the Brazilian electric energy consumption.

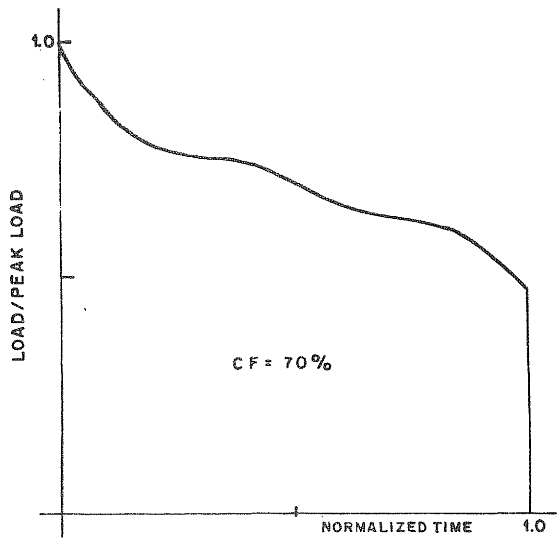
The Northeast Region is poor in terms of hydric resources, its main hydropotencials are located on São Francisco (6,552 MW), Northeast Atlantic (381 MW) and East Atlantic (370 MW) basins and almost all of them are already being exploited or under construction projects. The alternative adopted to fulfill the Northeast electric energy requirement in the future is to achieve the interconnection between North and Northeast. This interconnection is under construction through 500 KV transmission line, therewith the hydropotencials of Tocantins/Araguaia basin (see broken line in figure 2) will supply the system.

The electric demand forecast will probably be high due to large mineral and industrial projects as Projeto Carajás, Alunorte, Albrás and Alcoa (exploitation of iron, aluminium and alumina) and Projeto Itataia (exploration, processing and enrichment of uranium). Only these projects will require about 3,000 MW installed capacity.

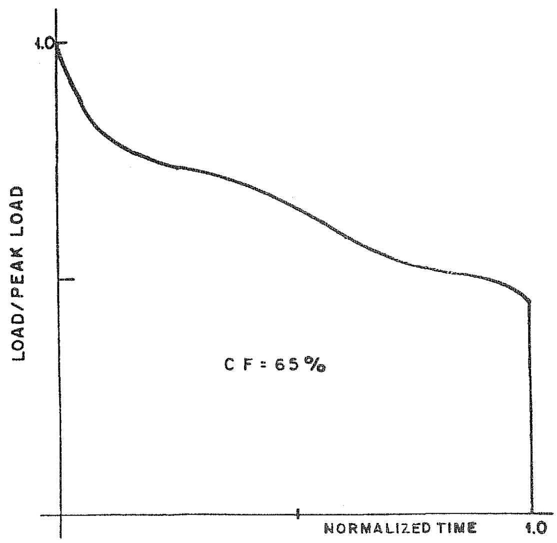
3.2 - Input Data

The main input data and assumptions considered in this study are shown as following:

. Load Duration Curves



LDC FOR FIRST AND FOURTH PERIODS



LDC FOR SECOND AND THIRD PERIODS

. Electric Energy Demand Forecast:

Year	Energy Demand (GWh)	Peak Demand (MW.Year)
1983	22534	4086
1985	32985	5381
1990	64967	11780
1995	87005	15776
2000	111977	20304
2005	139877	25363
2010	174640	31666

. The Fixed System

a. The installed units: thermal (oil) = 540 MW
hydro = 5641 MW
total = 6181 MW installed capacity

b. The commited units : hydro = 8086 MW installed capacity

Units	Installed Capacity (MW)	Operation
Boa Esperança II	126	1984
Tucuruí	3960	1984
Itaparica	1500	1985
Xingó	2500	1989

. The Hydro Units Candidates for North/Northeast System Expansion:

Name		Capacity MW	Capital Cost ($/kW) National	Foreign
	Santa Isabel	1760	599.0	106.0
	Santo Antonio	1370	666.0	117.0
North	Carolina	2226	706.0	125.0
	Itacaiúnas I	135	2061.0	364.0
	Itacaiúnas II	183	1854.0	327.0
	Farinha	69	3712.0	655.0
	Pão de Açúcar	330	1099.0	194.0
	Orocó	515	1107.0	195.0
	Alto Fêmeas	50	939.0	166.0
Northeast	Ibó	595	1276.0	226.0
	Sacos	114	1107.0	196.0
	Gatos I	30	1244.0	220.0
	Gatos III	36	1631.0	288.0
	Paratinga	440	1724.0	304.0

. Thermal Units Candidates for Expansion:

Type	Capacity MW	Capital Cost ($/kW) National	Capital Cost ($/kW) Foreign	Fuel Cost ¢/10^6 kcal	O&M Cost $/kW.Month
Nuclear	1245	1302.0	701.0	340.0	1.60
Coal	335	533.9	1188.4	860.0	1.42

4. Results and Conclusion

The optimum solution was obtained at the end of the 5^{th} of the cycle CONGEN-MERSIM-DYNPRO spending aproximately 13 hours CPU time. This solution add to the North/Northeast System, for the period of 1983 to 2010, a total of 17806 MW installed capacity, in accordance with the following distribution: 7x1245 MW nuclear units, 8x335 MW coal units and 17 hydro plants (see figure 3).

Due to the purpose of this study, as mentioned in section 3, the handling of the physical and econonomical information about hydro power units was not sufficiently accurate and the sensitivity study was not performed. In spite of this, it is possible to conclude that, due to a lack of hydraulic potencial in the Northeast Region (even supplemented by Tocantins/Araguaia basin potencial) the region will require the thermal introduction from 1999 on.

As to the modifications in WASP-III package for minimizing the CPU time, they will be implemented or not, depending on the CPU time spent in posterior applications, with the WASP-III package already implemented on the new HB-DPS 7 computer that will soon replace the computer presently used at CNEN. In this same view, some routines, must be introduced to simulate the operation of pluriannual regularization reservoirs hydro units and to introduce the transmission costs (long distance).

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APPENDIX A

a) The main characteristics of CII - Honeywell Bull computer DPS 6/64.

I) Hardware Configuration

- 2 MB core memory
- 16 magnetic disk units of 200 MB
- 4 magnetic tape units
- others peripherical components

II) Software Configuration

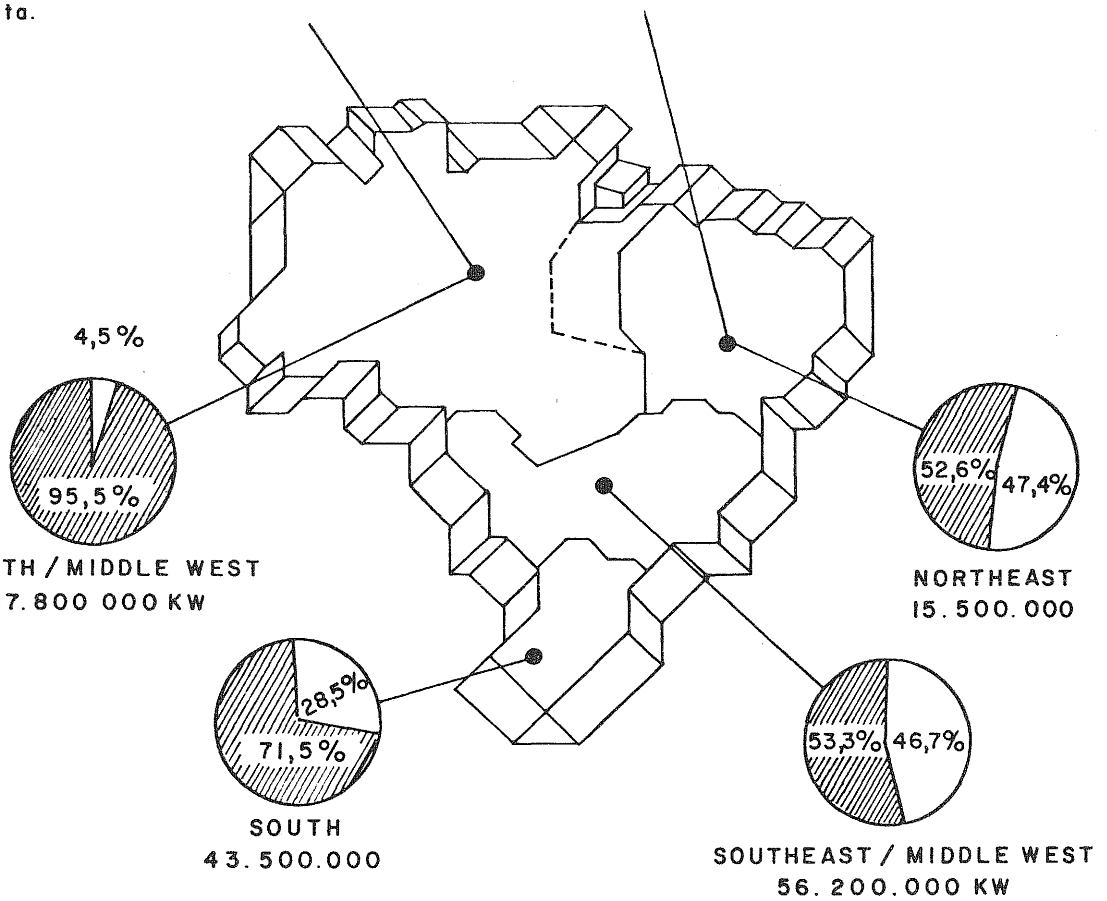
- Operating System GCOS - General Comprehensive Operating System
- Virtual Memory Management
- UFAS - Unified File Access System and BFAS - Basic File Access System
- BTNS - Basic Terminal Network System
- MCS - Message Control System
- TDS - Transaction Driven System
- COBOL, FORTRAN and GPL Compilers

b) List of some modifications carried out:

- Integer instead Integer*2
- * instead & in CALL command with alternate return
- BACKSPACE command for Variable Records (VS) is not allowed in the HB System. The alternatives to solve this problem:

Alternative 1:	Alternative 2:
- To especify the record size as fixed in the file allocation.	- To introduce the counter for DUMMY reading. - To rewind to the beginning of the file. - DUMMY reading until the desired record.
Consequences: - Increase of the CPU time - File space enlargement	Consequence: - Increase of the CPU time

	NORTH REGION	NORTHEAST REGION	BRAZIL
Installed capacity	1 085 MW	6 304 MW	38 904 MW
Consumption	2 850 GWh	18 131 GWh	131 590 GWh
Population	6 507 x 10^3 hab	36 680 x 10^3 hab	125 842 x 10^3 hab
Consumption per capita.	438 KWh/hab	494 KWh/hab	1 046 KWh/hab



THE BRAZILIAN HYDROPOTENCIAL

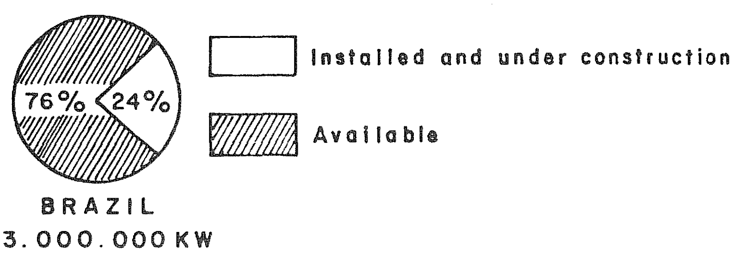


FIGURE 1 - SOME REGIONAL CHARACTERISTICS

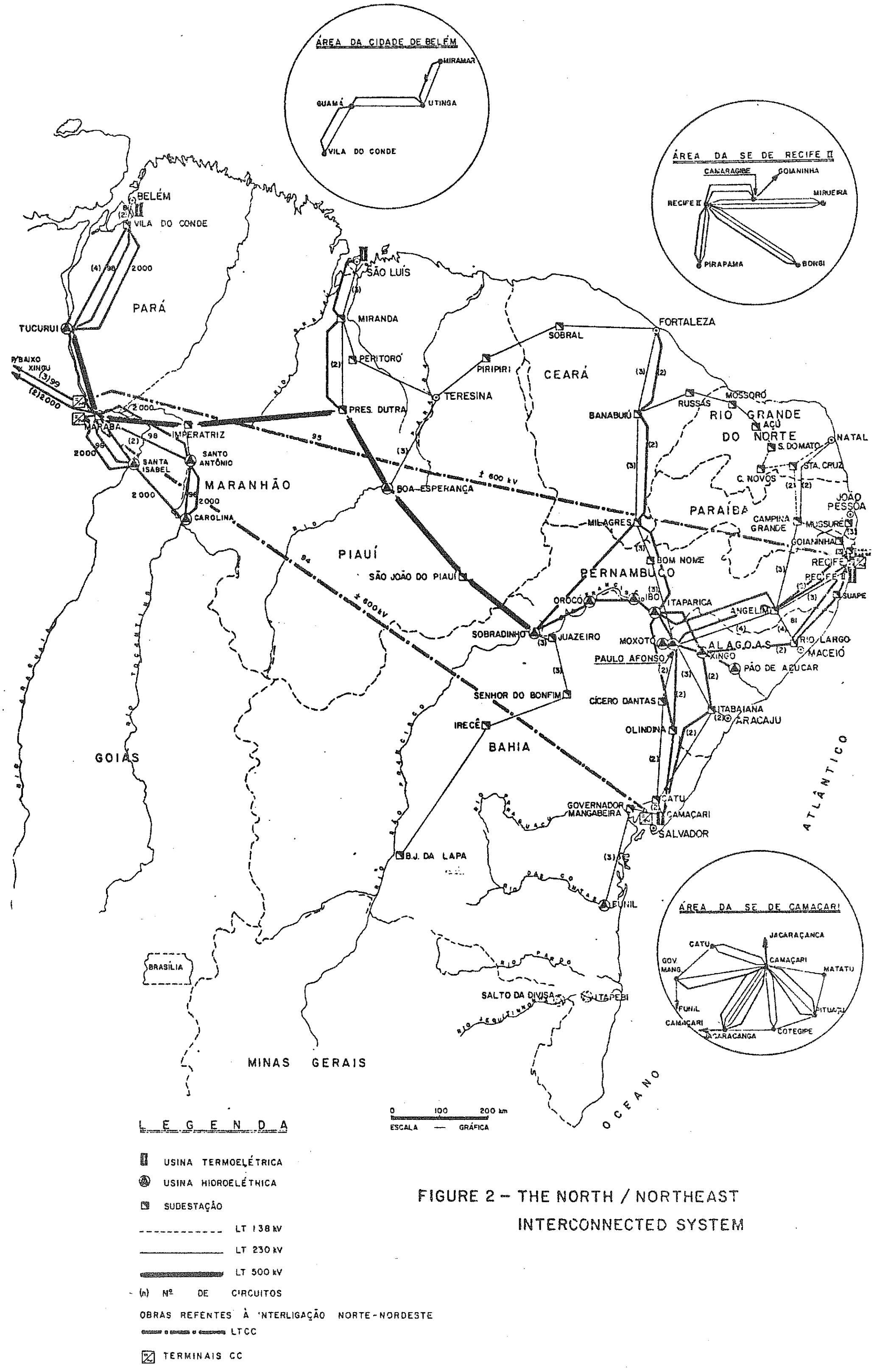


FIGURE 2 – THE NORTH / NORTHEAST INTERCONNECTED SYSTEM

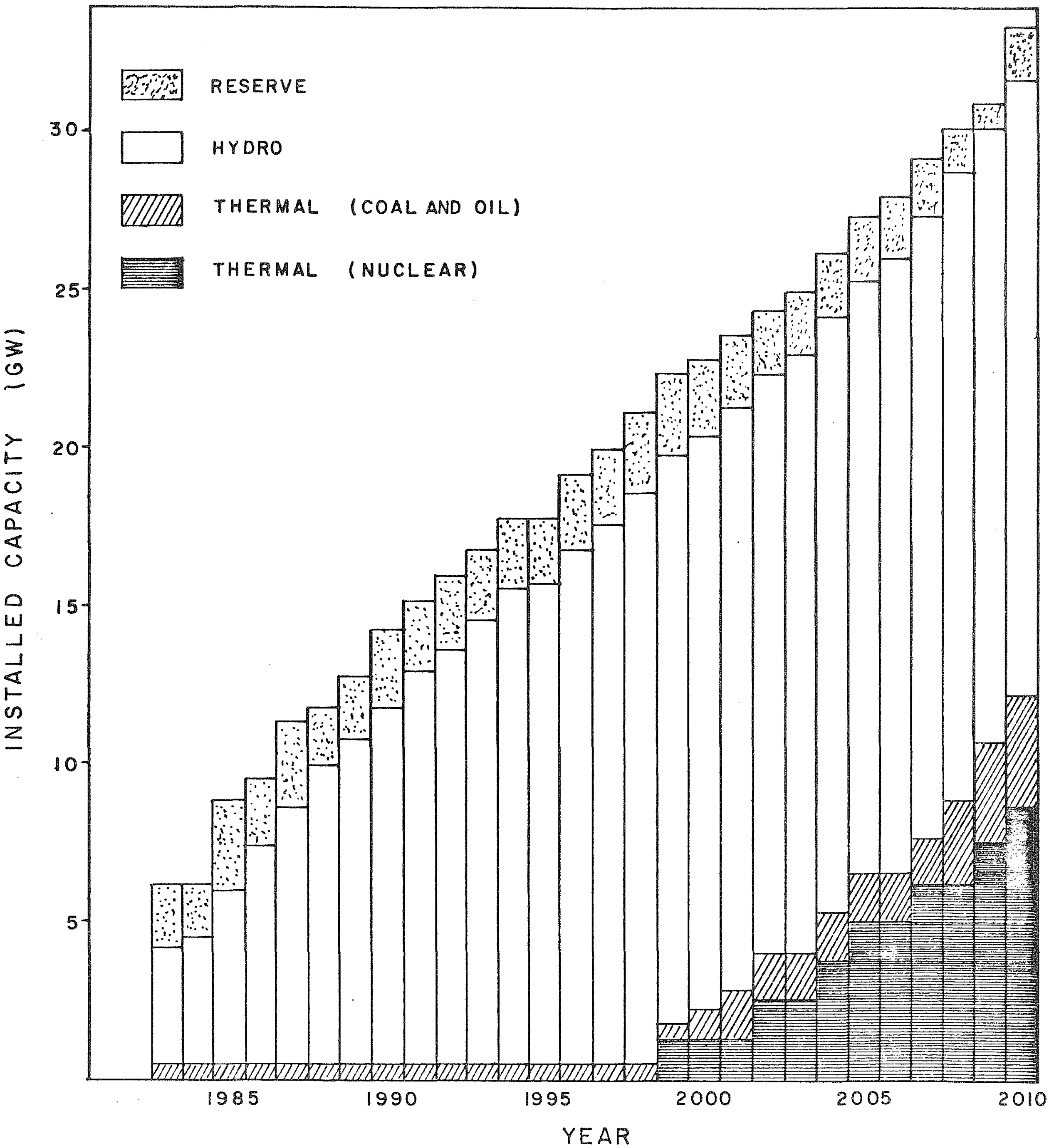


FIGURE 3 - THE NORTH / NORTHEAST SYSTEM INSTALLED CAPACITY

FUTURE DEVELOPMENTS OF IMPROVED VERSIONS OF THE WASP COMPUTER MODEL

by: P. Heinrich and P. E. Molina
International Atomic Energy Agency

The Wien Automatic System Planning Package (WASP) for electric generation expansion planning has been used by the IAEA to conduct Nuclear Power Planning Studies (NPPS) for requesting Member States. In conjunction with the MAED Model, WASP is intended to be used also for future assessment of the need for nuclear power in a given country through Energy and Nuclear Power Planning Studies (ENPPS) carried out for requesting Member States.

From the very beginning of development of the WASP Code, greater emphasis has been put into maintaining versatility so as to permit its implementation in developing countries. Nevertheless, it has been applied by some utilities also in industrialized countries so that now WASP is a well recognized methodology for generation expansion planning.

Three versions of WASP have been developed by the IAEA during the period 1972-1983, namely WASP, WASP-II and WASP-III. WASP-II and WASP-III have been released to many interested Member States and several international organizations. Extensive training in the use of WASP has been given at the IAEA in Vienna and at the Argonne National Laboratory (ANL) in the USA.

The improvements developed by the IAEA which were implemented in the latest version, WASP-III, provide a better and more detailed representation of hydroelectric power plants and assessment of the competition of these power plant types for expanding generating systems. The latter was achieved by the introduction of two composite hydro plants, each representing a series of competing hydroelectric projects, and including the cost of the energy not served as part of the objective function.

The main disadvantage of WASP-III when compared to the earlier version WASP-II is its inability to consider pumped storage plants in the simulation of system operation.

Introduction of pumped storage plants is the logical step after most conventional hydro resources of a country or region have been exploited, but the decision to construct the plant is mainly based on economic grounds. Economic operation of a pumped storage scheme proves to be more efficient in systems having relatively very low production costs for base load operation such as in the case when this base portion is supplied by nuclear plants. Thus, pumped storage plants should be considered when examining alternative expansion strategies which include nuclear power plants.

WASP-III permits treating several types of hydroelectric power plants, namely run-of-river, and plants of daily, weekly and seasonal regulating cycle, and the characteristics of each plant to be considered for simulation purposes are derived from the individual characteristics specified by the user and several hypotheses concerning the operation of each type of plant. For plants of the seasonal regulating cycle type, the basic characteristics on energy inflow, capacity and minimum generation requires prior optimization of the operation of the plant over the year, thus imposing an extra burden on the user during the data preparation stage. Moreover, the optimized characteristics are highly dependent on the composition of the system capacity available and the characteristics of the load for each period. Thus, there is a need to introduce optimization of the seasonal regulating hydro plants as a prior step to the yearly simulations.

This paper discusses the state of development of WASP with regard to the introduction of pumped storage plants and optimization of seasonal regulating hydro plants in WASP-III, as well as some other intended future developments of the WASP program.

1. Introduction

The Wien Automatic System Planning Package (WASP) was originally developed by the Tennessee Valley Authority (TVA) and the Oak Ridge National Laboratory (ORNL) of the U.S.A. to meet the needs of the "Market Survey for Nuclear Power in Developing Countries" which was conducted by the IAEA in the period 1972 - 1973, Refs. [1]-[2]. Based on the experience gained in using it, many improvements were made to the computer code by IAEA Staff leading in 1976 to the WASP-II version, which has been widely used by the Agency and Member States, Ref. [3]. Later, the needs of the United Nations- Economic Commission for Latin America (ECLA) to study the interconnection of the electrical grids of the six Central American countries, where a large potential of hydroelectric resources is available, and further recommendations given in 1979 by an IAEA Advisory Group on Electric System Expansion Planning led to a joint ECLA/IAEA effort to develop the WASP-III version during the period June 1978-Nov. 1980, Ref. [4]. The improvements developed by the IAEA and implemented in the WASP-III version of the computer program included principally: a better and more detailed representation of hydroelectric power plants, competition between two series of candidate hydroelectric projects, probabilistic simulation with four composite hydro plants, and consideration of the cost of the energy not served as part of the objective function to be optimized. All these features have rendered the WASP-III package particularly suitable for developing Member States as it has been confirmed by the many requests for release received at the Agency. Further, other special features included in WASP-III such as internal checks of the input data and improved computer printouts containing more information useful to the user, have made the model more user-friendly as it has been demonstrated during training on its use.

In summary, WASP-III is designed to find the economically optimal generation expansion policy for an electric utility within user-specified constraints on reliability and reserve capacity limits. It uses probabilistic simulation of system operation and dynamic programming for optimizing system expansion, and can be considered to represent the current state-of-the art in flexible computer models to meet the evolving needs of electric utilities for generating expansion analysis. There are, however, some areas where further enhancements to this planning tool are required.

The following sections describe the state of development of the enhancements to WASP-III being currently done at the IAEA, as well as some other further developments which may be undertaken in future. The last two sections discuss aspects related to statistics on release of the program to IAEA Member States, training on its use by IAEA, and use by IAEA and recipients of the programs for generating expansion planning studies.

2.0 Enhancements of WASP-III currently undertaken

2.1 Introduction of pumped storage plants

When comparing the conceptual differences between the WASP-II and WASP-III versions of the package (see Table 1), it becomes apparent that the only advantage of WASP-II is its ability to consider pumped storage plants in the simulation of system operation. The decision for not including pumped storage plants in WASP-III was made at an early stage of development of the computer program and it was based on special considerations made at that time, namely:

a) in order to keep the probabilistic simulation algorithm within reasonable limits of complexity particularly when considering the level of complexity already introduced by the consideration of two peaking composite hydro plants (see attachment 1)†.

b) trying to maintain the requirements for computer memory within limits acceptable for the size of computer normally available in developing countries.

c) the consideration that the WASP-III version would be most useful for countries having large hydroelectric potential for future expansion of the system and where normally the needs for pumped storage development would not become an economic alternative well-up to the beginning of the next century.

† Editor's Note: Attachments I and II could not be included in this printing because of their large number of pages. The readers are suggested to write to the authors for the full test.

All the above reasons, combined with the fact that limited resources for manpower and funds were available at the time of developing WASP-III and that there was an urgent need to have the code available for the study being executed by ECLA for the six Central American countries, prevailed in the decision for not including pumped storage in the probabilistic simulation. Nevertheless, recognizing the potential advantages of this type of generating plants, it was planned to treat them with high priority in the next development for the WASP program.

In fact, the introduction of pumped storage plants is the logical step after most conventional cheap hydro resources of a country or region have been exploited, but the decision to construct the plant is mainly based on economic grounds. Assessment of the economic competition of this type of plants requires the comparison of the cost for developing the plant against the benefits on overall system operation; the latter will be highly affected by the characteristics of the system under consideration such as load variation with time and ratio of minimum to maximum load and the composition of the system capacity. In general, economic operation of a pumped storage scheme proves to be more efficient in systems having relatively very low production costs for near base load operation and high production costs for peaking load operation, such as in the case when the base portion of the load is supplied by nuclear or coal units combined with run-of-river hydro plants and the peaking portion is provided by gas and oil-fired units. Thus pumped storage plants should be considered when examining alternative expansion strategies which include nuclear power plants.

Several IAEA developing Member States are already facing this case since they already have pumped storage plants in operation in order to reduce the addition of peaking thermal units and the generation of some of the existing peaking units, thus to reduce consumption of expensive fuels. Other countries, although endowed with enough conventional hydroelectric resources are considering pumped storage plants as expansion candidates either for the same reasons or in connection with other thermal base-load candidates such as nuclear or coal. Several requests in this direction have been received at the IAEA from interested Member States.

Table 1 Most important conceptual differences between WASP-II and WASP-II

Concept	WASP-II Model	WASP-III Model
Energy not served cost	No	Yes
Type of hydroelectric plants	. Run-of-river . Peaking . Emergency	. Run-of-river . Daily regulating cycle . Weekly reculating cycle . Seasonal regulating cycle
Optimization of hydroelectric project parameters	No	Yes
Number of series of competing hydroelectric projects	One series (20 projects)	Two series (30 projects each)
Probabilistic simulation of power plants operation	Made with three composite hydro plants: . Run-of-river . Peaking . Emergency	Made with four composite hydro plants . Run-of-river (2) . Peaking hydro A . Peaking hydro B
Calculation of ENS and LOLP for the case of shortage in hydro-electric energy	Incorrect	Correct
Input data for hydroelectric projects	Complex	Simplified
Input data on load duration curves	Fifth order polynominal description	Fifth order polynominal or point-by-point description
Reports and printout formats	Normal	Highly improved
Input data checks	Poor	Highly improved

In certain special cases the WASP-III code has been used to approximate the operation of existing pumped storage plants by using one of the two composite hydro plants permitted by the code and adjusting the O&M costs of this plant type so as to reflect the increased operation of thermal power plants in order to supply the pumping requirements. Obviously this approach requires exact knowledge of the system composition and of which thermal plants will be used to provide the pumping requirements; the latter is not always known in power system expansion planning. Further, although the pumping-generating cycle cost influence is somehow taken into account in the economic comparison of expansion alternatives, the total system electricity generation is underestimated by this approach.

With these objectives in mind, the IAEA awarded a research contract to the Boris Kidric Institute of Nuclear Sciences of Yugoslavia in 1982, in order to include the treatment of pumped storage plants in the WASP-III Computer Program.

Although, still at the phase of development, it is expected that concrete results from this project will be available to interested Member States during next year.

Attachment 1 presents a background information related to the treatment of pumped storage plants in WASP-II and how it is envisaged to be included in the WASP-III version. [Ref. 5].

2.2. Optimization of large-reservoir hydroelectric power plants

As can be seen in Table 1, WASP-III permits treating several types of hydroelectric power plants, namely run-of-river, and plants capable of daily, weekly and seasonal regulating duties, and the characteristics of each plant to be considered for simulation purposes are derived from the individual characteristics specified by the user and several hypotheses concerning the operation of each type of plant. Further, and also for simulation purposes, all individual hydro projects are combined into one of the two composite hydro plants considered by WASP-III: hydro plant A and hydro plant B.

The type of hydro projects to be composed in each hydro plant is controlled by the user. It is, however, recommended to use plant type A to combine all hydro projects having no regulating or rather limited regulating capability and to leave plant type B to describe the composite characteristics of seasonal regulating cycle type. For plants of this type, the determination of the basic characteristics of minimum generation requirements, total available capacity and the energy inflow require that prior optimization of the operation of the plant over the year should be performed; thus, imposing an extra burden on the user during the data preparation stage of the WASP study. Moreover, the optimized characteristics of these plant types are highly dependent on the composition of the system capacity available and the load characteristics for each period, to which the user has very little possibility of control during variable expansion runs of the program involving several expansion configuration of the system. Therefore, there is a need to introduce in WASP-III optimization of the use of water in seasonal regulating hydro plants as a prior step to the yearly simulations.

This task has been accomplished at the IAEA by introducing several modifications mainly in the simulation module (MERSIM) of WASP. They lead to an approximate simulation of system operation for each configuration considered before entering into the full simulation process. This additional step is executed for each hydrocondition in order to optimize the use of water in large reservoirs. The input parameters for these plants remain basically intact with respect to WASP-III except that additional information is required: whether this optimization is needed to be executed, the number of equal steps into which the volume of the composite hydro plant representing the large reservoirs is to be subdivided and the initial and last level of the composite reservoir. Optimization is executed by means of dynamic programming and including in the process the cost of the unserved energy. The results of the process are the intermediate levels of the reservoirs leading to optimal use of water for electricity generation in these plants.

A great effort was made at IAEA in order to minimize the computer time required for this additional simulation step and this was solved by a unique process related to dynamic progamming with the constraints imposed by the problem. In principle, the total number of simulations to be carried out at each period was reduced to the minimum possible as described in the attachment.

The program has been tested at the IAEA using the sample problem developed for documenting the WASP-III Users' Manual. The initial results are encouraging since they showed a good co-relation between the total operating costs of the system after the optimization and the number of steps into which the reservoir is divided up to a certain number. In principle, the computer time required for this additional simulation only affects the total computer time needed by MERSIM by a factor close to 2 for a reasonable number of steps in the reservoir (N).

The IAEA in co-operation with certain Member States intends to conduct some comparative studies of this optimization procedure using more realistic power generating systems before diseminating it among the WASP recipients.

A description of the algorithm used by this optimization procedure is given in Attachment 2 [Ref. 6].

2.4 Further development of WASP at the IAEA

Depending on manpower and funds availability, future improvements of WASP are considered:

a) Incorporation of a more efficient computational technique for simulation of system operation in order to reduce by about a factor of 10 the computer time required to carry out a WASP study. In principle, the so-called "segmentation method" has been selected to achieve this task.

b) Adaptation of WASP to run on mini-computers in the class of the so-called "professional computers", such as the IBM-PC.

The computational technique to be used in order to achieve the first objective will provide a much-improved representation of the operating characteristics of power plants and electric power systems, thereby allowing the following sub-objectives to be accomplished too, with very modest increase in effort:

a.1 improved modelling of energy storage units (e.g. pumped storage),

a.2 more realistic maintenance scheduling which will permit effectively removing the units from the system while in maintenance,

a.3 incorporation of forced outage rates and maintenance scheduling for hydroelectric units,

a.4 consideration of forced outage rates as a function of plant age,

a.5 allow the date of start of operation and date of retirement for the FIXSYS plants to be more precisely specified (e.g. a fraction of the year).

3. Training in the use of the WASP program

In the period January 1975 - June 1983, 166 senior engineers and power system planners from 51 countries and 3 international organizations have been trained by the IAEA in the use of the various versions of WASP. The major training effort was made at the Argonne National Laboratory (ANL), USA, under an IAEA-DOE sponsored training course on Electric System Expansion Planning which has been given five times in the period January 1978 - June 1983. Some countries which had already sent specialists to Vienna for IAEA training on WASP during the period Jan. 1975 - Dec. 1977 also sent participants to the ANL courses. As a result, 52 participants from 20 countries and 3 international organizations received their training in Vienna, and 114 participants from 43 countries attended the ANL courses on Electric System Expansion Planning. Altogether, the trainees performed about 70 power generating system expansion studies using the various versions of WASP available to them.

4.0 Release of the WASP program

WASP has been released to IAEA Member States having the necessary analytical and computer capabilities, under special arrangements. Up to June 1983, WASP-II has been released to 41 countries and WASP-III to 44 countries, 20 of which reported to have used WASP-II in 53 studies and to plan at least 30 more WASP studies in the future. Further, 5 international organizations - ECLA, ESCAP, IBRD, CIER and WB - are recipients of both versions of WASP. ESCAP and ECLA reported to the IAEA of having more than 36 WASP studies involving a total of 10 countries in South East Asia and Central America.

Additional requests for release of WASP-III are expected to be received in the future from IAEA Member States.

The IAEA is prepared for the release and to provide the necessary technical assistance for implementing WASP in the recipient country.

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