Nuclear Power and its Fuel Cycle

TECHNICAL REPORTS SERIES No. 241

Expansion Planning for Electrical Generating Systems

A Guidebook

INTERNATIONAL ATOMIC ENERGY AGENCY, VIENNA, 1984

EXPANSION PLANNING FOR ELECTRICAL GENERATING SYSTEMS

A Guidebook

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The Agency's Statute was approved on 23 October 1956 by the Conference on the Statute of the IAEA held at United Nations Headquarters, New York; it entered into force on 29 July 1957. The Headquarters of the Agency are situated in Vienna. Its principal objective is "to accelerate and enlarge the contribution of atomic energy to peace, health and prosperity throughout the world".

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EXPANSION PLANNING FOR ELECTRICAL GENERATING SYSTEMS:
A GUIDEBOOK

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FOREWORD

The purpose of this guidebook is to advise managers, engineers and operators of electric power systems in developing countries on the principles and methodologies that should be applied when planning the expansion of their electric power generating systems.

The guidebook outlines the general principles of electric power system planning in the context of energy and economic planning in general. It describes the complexities of electric system expansion planning that are due to the time dependence of the problem and the interrelation between the main components of the electric system (generation, transmission and distribution). Load forecasting methods are discussed and the principal models currently used for electric system expansion planning presented. Technical and economic information on power plants is given. Constraints imposed on power system planning by plant characteristics (particularly nuclear power plants) are discussed, as well as factors such as transmission system development, environmental considerations, availability of manpower and financial resources that may affect the proposed plan. A bibliography supplements the references that appear in each chapter, and a comprehensive glossary defines terms used in the guidebook.

This guidebook is published as part of a series of technical reports on Nuclear Power and its Fuel Cycle compiled by the IAEA's Division of Nuclear Power. Other documents already published in this series include:

Manpower Development for Nuclear Power: A Guidebook, Technical Reports Series No. 200 (1980)
Technical Evaluation of Bids for Nuclear Power Plants: A Guidebook, Technical Reports Series No. 204 (1981)
Guidebook on the Introduction of Nuclear Power, Technical Reports Series No. 217 (1982)
Interaction of Grid Characteristics with Design and Performance of Nuclear Power Plants: A Guidebook, Technical Reports Series No. 224 (1983).

The guidebook reflects the experience gained in conducting five Inter-Regional Training Courses on Electric System Expansion Planning at Argonne National Laboratory in co-operation with the Government of the United States of America. The material was written mainly by staff members of Argonne National Laboratory and the IAEA, with contributions from other lecturers at the training course.

The Division of Nuclear Power of the Agency would be grateful to receive comments from readers based on the study and use of the guidebook.

ACKNOWLEDGEMENTS

The individuals mainly responsible for developing this guidebook are W. Buehring and C. Huber (Argonne National Laboratory, USA), and J. Marques de Souza (Division of Nuclear Power, IAEA). Their efforts ranged from defining the scope and structure of the guidebook and co-ordinating arrangements with authors to writing much of the material and revising the final draft.

The Agency wishes to acknowledge the valuable contribution of the Advisory Group that met in Vienna from 12 to 16 September 1983 to review the guidebook.

The Agency also wishes to thank L. Abramson (US Nuclear Regulatory Commission), R. Beckwith (Commonwealth Edison, USA), J. Delson (Electric Power Research Institute, USA), and E. Skoknic (ENDESA, Chile) for voluntarily reviewing the guidebook and suggesting improvements.

P. Molina (Division of Nuclear Power, IAEA) was responsible for co-ordinating work on the illustrations and producing those figures which were created at the IAEA's computer facilities.

The Agency wishes to thank all those who contributed to this guidebook. The details of their contribution are as follows:

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[1] Now at Comisión Chilena de Energía Nuclear, Chile.

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[2] Additional support provided by the Electric Power Research Institute, USA.

CONTENTS

Chapter 1
INTRODUCTION

The function of an *electric power system* is to provide a reliable and continuous source of electricity whenever requested. To provide this service, each of the three main components of an electric power system — *generation, transmission and distribution* — must perform as required. *The generation system* consists of physical facilities that convert energy resources (e.g. coal, oil, uranium, running bodies of water) into electricity. The *transmission system* then transports the generated electricity to the local service communities. The *distribution system* within each community provides the actual connection from the transmission system to each customer, and enables the customer to consume electricity upon demand.

An electric power system is a dynamic system which is a balance of supply and demand:

(a) The *supply* of electricity, consisting of physical devices that must be designed, constructed, operated, maintained, and eventually replaced as each device wears out, and

(b) The *demand* for electricity, which changes as a function of time from instantaneous (seconds, minutes), to short term (hours, days) and to the longer term (months, years).

Therefore, a major objective for an electric power system is to keep a continual balance between the supply and demand for electricity.

Power system expansion planning is the process of analysing, evaluating and recommending what new facilities and equipment must be added to the power system in order to replace worn-out facilities and equipment and to meet changing demand for electricity. Planning methodologies have been developed for the three main components of a power system (generation, transmission, distribution), and each one is in itself a major subject of study.

This guidebook is concerned with the methodologies developed for planning the expansion of the generation component of a power system. Since all three components are interrelated, and each can affect the planning of the other two, any expansion plan developed for one component should be evaluated taking the others into account. Therefore, even though this guidebook discusses planning the generation component of an electric system, the plan should also be evaluated in terms of the transmission and distribution at some point in the planning process.

1.1. HISTORY OF THE GUIDEBOOK

This guidebook is the direct result of the Electric System Expansion Planning Course sponsored by the IAEA and the United States Government, and conducted at Argonne National Laboratory (ANL) in the USA. The course is part of the IAEA's role in providing technical assistance to developing Member States (further described in Section 1.2), and was given five times between 1978 and 1983. The course is open to all IAEA Member States, with special consideration to developing countries. Experts on expansion planning from the IAEA and ANL, together with specialists from electric utilities, research organizations, universities, regulatory agencies and private industry the world over, participate in conducting the course.

The course has generated a large volume of information and reference material. It was proposed that the IAEA and ANL jointly organize the course material, prepare new material on several topics, and create a single document that could be used as the basic reference during future courses, and that would serve as a practical reference for electric system planners throughout the world. The IAEA and ANL, with the financial support of the US Government and the assistance of numerous international authors, have therefore developed this guidebook in its present form.

1.2. STRUCTURE OF THE GUIDEBOOK

This book is designed to be a practical guide to electric generation expansion planning. It presents concepts and methodologies that have been developed to enable the planner to make an analytical approach to the analysis and evaluation of expansion planning alternatives. This not only assists the planner in defining, organizing and quantifying the objectives of the expansion plan, but also enables the planner to demonstrate and reproduce the planning process itself.

The guidebook is organized into 11 main chapters, each one presenting a major subject, and 10 appendices, containing additional material, including technical and economic data. A bibliography and a glossary complete the guidebook.

Chapter 2 introduces expansion planning by first establishing its role in the context of overall energy planning. It is important that the system planner understands (a) how electric system planning interacts with planning the overall energy needs of a country (or other government organization); (b) how the planning of the electric system can affect overall energy use, availability and cost; and (c) how overall national energy planning may influence planning of the electric system.

Chapter 3 introduces electric power system planning and defines the scope of the remainder of the guidebook: expansion planning of the generation component of the power system. The overall objectives for generation expansion planning are presented and the complications faced by the generation planner are discussed.

Chapter 4 introduces the concept of forecasting the demand for electrical load and energy. The *demand* side of the power system is evaluated by presenting the philosophy of forecasting and the perspective in which forecasting should be viewed. The chapter also discusses the time dependence of electricity consumption and the appropriate methodologies for projecting electricity consumption for various time frames.

Key principles in electric power planning (and in any other planning that requires spending large sums of money over a period of time) are the time value of money and basic engineering economics. Chapter 5 reviews these concepts, which are used later in the guidebook.

Chapter 6 presents methodologies for determining and evaluating the costs of a generating system. The chapter describes how power plant investment and operating costs are usually considered and how costs are typically recovered in the basic price of electricity. Technical details of power plants are defined which affect the evaluation of the operating costs of a generation system. The chapter also presents an uncertainty analysis methodology, which enables the planner to compare power plant alternatives for those cases where the levels of experience and knowledge (which can greatly affect cost estimates) of each alternative plant differ. Finally, various production cost methodologies are presented, from very basic methods (enabling the reader to understand the analysis required) to sophisticated methods that require computer models to perform the enormous number of calculations needed.

Chapter 7 deals with a key question: to what level can the customer rely on the power system to supply the electricity requested? The chapter shows how power system reliability can be measured and presents methods for determining the value of reliability to the service community. Studies and methodologies used by a number of countries are described.

Up to this point, the guidebook presents analytical methods in terms of a generating system consisting primarily of thermal power plants. Chapter 8 expands this with concepts specific to the analysis and evaluation of hydroelectric power plants and the special factors that must be considered when a large proportion of the generating system consists of hydroelectric plants. This is especially important in countries which have already developed low-cost hydroelectric plant sites, and which have only higher-cost sites and thermal power plants as alternatives for future plant additions.

A power plant is a physical facility composed of many different types of equipment and materials. The characteristics of each type of power plant affect the way the plant is operated. Chapter 9 presents characteristics that can affect the way the plant is considered in an expansion plan (e.g. maintenance requirements and startup times) and indirect characteristics of a plant that can affect the service community (e.g. environmental impact and financing).

Chapter 10 shows how computerized models can assist the planner. The role of computerized models and the features required by a model for performing generation expansion planning are discussed. Different types of models are described and the benefits and limitations of each methodology noted. To demonstrate how the concepts and methodologies presented in the guidebook have been implemented in actual computerized models, a number of models are briefly described. This is not an all-inclusive list (and not a recommendation of any one model) but rather a sampling of models that have taken different approaches to the generation expansion planning problem.

To present a computerized model in further detail, Chapter 11 describes the Wien Automatic System Planning Package (WASP), which is used by the IAEA and many organizations world wide for performing long-range generation expansion planning studies. This chapter describes the methodologies used in WASP and how the model is organized and operated. It also points out the computer requirements for running the model, its unique features, and its limitations.

The appendices complement the main text and cover computer models and techniques, technical and economic data.

Appendices A to D present computer models and analytical techniques which can be used for evaluating generation expansion plan alternatives. Appendix A describes the MAED computer model, used by the IAEA for energy planning studies (see Chapter 2). Appendix B describes the MNI computer model, developed by Electricité de France for generation expansion planning studies in France. Appendix C presents two recently developed analytical techniques that can decrease the computing requirements for computer models using the probabilistic simulation method for simulating the electric system. The first, known as the *cumulant method,* has been implemented in a number of models. The second, the *segmentation method,* has recently been proposed for even greater efficiency. Appendix D presents auxiliary computer models that may help the planner in further analysis of data used in the expansion plan. These models deal with evaluation of investment costs for power plants (CONCEPT, ORCOST), the nuclear fuel cycle (FUELCASH, SCENARIOS), and power system analysis (MASCO, FRESCO).

The accuracy of an expansion plan is a direct function of the quality of the information used in its development. The planner should strive to obtain the most up-to-date and accurate technical data available (for fuels as well as power plant investment and operating costs). This can be time consuming, and is especially difficult during preliminary studies or when conducting training courses (such as the IAEA courses). Appendices E to I provide typical information that can be useful to the planner until more up-to-date information is obtained.

Appendices E and F concern fuels. One of the major complications with fuels is the inconsistent definition of units and energy content of gas, oil and coal. Appendix E defines the most widely used definitions for fuels and their energy content and includes a survey of fuel prices in the world market. Appendix F concerns the nuclear fuel cycle, which is the second most important item (after investment costs) in determining energy generation costs for a nuclear power plant. This appendix describes the steps in the fuel cycle and presents examples of the calculation.

Appendix G presents the technical operating characteristics of power plants that must be considered in making an expansion plan. These data reflect the actual operational experience of each type of power plant and not the 'design' characteristics stated by specific power plant suppliers.

Appendix H presents investment costs, construction times and operating costs for thermal power plants. Costs are described in terms of the major components and parameters which contribute to the total investment and operational costs of a power plant. This enables the planner to understand what can influence investment and operating costs, thus assisting him in developing these costs for a specific expansion plan.

Appendix I is a parametric analysis of hydroelectric power plant costs, which can be helpful in determining the costs for each hydroelectric plant considered. This is especially important since the total cost of a hydroelectric plant greatly depends on the site where the plant is to be located. Appendix J outlines the types of data used in performing an expansion plan.

A bibliography lists additional study material recommended by the various authors. A glossary defines terms used in the guidebook.

1.3. THE IAEA'S ROLE IN ENERGY PLANNING

In meeting its objective of assisting developing Member States in the peaceful uses of nuclear energy, the Agency conducts an extensive and comprehensive programme of work in nuclear power planning and implementation, including economic assessments to determine the appropriate role of nuclear energy within the national energy plan of developing Member States. These assessments include three major types of interdependent and closely related activities:

(a) Development of appropriate methodologies specifically adapted to developing countries;
(b) Conducting training courses on energy and nuclear power planning techniques, including use of methodologies developed by the Agency;
(c) Conducting energy and nuclear power planning studies in co-operation with the Member States requesting them.

Close co-operation has been established with other international organizations, for example the World Bank (IBRD) in joint IAEA/IBRD electric power sector assessment missions to developing countries.

1.3.1. Estimating future electrical energy needs

One of the most important determinants of the need for nuclear power is the projected future demand for electrical energy. Experience showed that the information on electricity demand supplied by developing countries was often not developed with a systematic procedure which would ensure internal consistency with their main economic and industrial development objectives and possibilities. The electricity demand projections therefore often proved to be a weak point in the resulting estimates of the role of nuclear power in a country's energy supply.

To improve estimates of future electrical energy needs, the IAEA developed the Model for Analysis of Energy Demand (MAED). This computer model (described in Appendix A) provides a flexible simulation framework for exploring the influence of social, economic, technological and policy changes on the long-term evolution of energy demand.

1.3.2. Analysing the economics of system expansion

Once the electrical energy needs are estimated, the electrical generating system must be planned to meet these long-range needs. To assist in this planning, the Wien Automatic System Planning model (WASP) is provided by the Agency. WASP (described in Chapter 11) is a system of computer programs which uses dynamic programming techniques for economic optimization in electric system expansion planning.

The WASP model is structured in a flexible modular system which can treat the following aspects of an evaluation:

- Load forecast characteristics (electric energy forecast, power generating system development),
- Power plant operating and fuel costs,
- Power plant capital costs,
- Power plant technical parameters,
- Power supply reliability criteria,
- Power generation system operation practices.

1.3.3. IAEA training courses in energy planning

To develop expertise within Member States which would enable them to undertake their own projections and planning, the Agency conducts two courses to train specialists from developing Member States in techniques for energy demand analysis and electric system expansion planning.

1.3.3.1. Training in energy demand analysis

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 an understanding of the appropriate role for nuclear energy. It is not restricted to those countries already committed to using nuclear energy but is open to all developing Member States of the Agency and to participants interested in non-nuclear as well as nuclear energy technologies. The aim is to improve a country's ability to make a careful and objective choice among the various available energy options.

Even among energy planners, it is often thought that energy planning is only a question of economic analysis involving sophisticated computer models. This training course is designed to correct such a simplistic view and to show that good energy planning involves many aspects of technical as well as economic information. Particular attention is given to the link (too often disregarded) between the choice of the primary energy source and the end-use energy needs of the consumer.

Initiated in 1978 by the National Institute of Nuclear Science and Technology (INSTN) at Saclay, France, this course has been given three times in French (1978, 1979 and 1980 at Saclay, France), once in Spanish (1981 at Madrid, Spain) and twice in English (1982 at Jakarta, Indonesia; 1983 at Ljubljana, Yugoslavia).

During the first week of the currently three-week energy planning course, participants concentrate on the technical analysis of different energy chains (nuclear, coal, oil, gas, hydroelectric, solar, etc.) and examine all the steps from the production of primary energy to the final use of energy. The benefits and disadvantages of each energy chain are systematically described in a manner designed to increase the participants' awareness of the complementary aspects of the various energy sources.

The second week is devoted to the economic and financial analysis that should be part of energy planning. Energy models are presented briefly, but it is emphasized that they are no more than useful tools and cannot replace the comprehensive analysis and intelligent judgement of the energy planners themselves.

The third and last week is spent on the analysis of case studies, about half of which are based on results of extended studies previously carried out in various countries. The other case studies are hypothetical problems which are analysed by working groups of five or six trainees guided by one or two lecturers. The conditions which must exist as a prerequisite to using nuclear power in a developing country are emphasized, including:

- A national legal framework and a workable organizational infrastructure,
- Adequate human resources,

- Engineering capabilities permitting decision-making and technology transfer;
- An adequate level of national industrial development;
- Proper size and structure of the electrical transmission system to assure grid stability under both normal operation and transient conditions.

From 1978 through 1983 more than 170 senior engineer-economists from 55 countries were trained in energy planning. This course has been very successful, largely because Member States have always nominated highly qualified participants, but also thanks to the strong support of the contributing countries and organizations: Argentina, France, the Federal Republic of Germany, Indonesia, Spain, the United States of America, Yugoslavia, the United Nations Division for Natural Resources and Energy (DNRE), the World Bank (IBRD), UNESCO and, in particular, the National Institute of Nuclear Science and Technology (INSTN) at Saclay.

1.3.3.2. Training in electric system expansion planning

The object of the Agency's course on Electric System Expansion Planning is to train specialists in planning the expansion of an electric generation system. It encourages the use of WASP for carrying out such planning, while pointing out that the WASP study is only part of an overall decision process, which should also include factors such as requirements for transmission, finance and manpower. In the period 1975–1983, more than 160 senior engineers and power system planners from 50 countries have been trained. From 1975 to 1977, training was carried out by the Agency at its Headquarters in Vienna. During 1978 to 1983, the IAEA training course, Electric System Expansion Planning (ESEP), sponsored by the US Department of Energy, was given five times at Argonne National Laboratory, USA, with participation by 114 engineers and electric system planners from 43 countries. (Preliminary versions of the present guidebook have been used as a training manual for the course since 1983.) After completing the course, a trainee should be able to carry out studies to determine economically optimal expansion programmes including, in particular, the economically optimal share of nuclear power. The main subjects of the ESEP course are:

- Technical and economic characteristics of electric power plants,
- Principles of generation expansion planning,
- Interactions between electric grid and generation expansion planning,
- Characteristics of the WASP model and its auxiliary programs,
- Evaluation and presentation of input data for WASP,
- Analysis of optimum solutions,
- Preparation of a study report.

The training course is open every year to about 25 candidates from all developing countries. Candidates are asked to apply in national teams of two or more persons with experience in power system planning; this helps each national team to carry out an ESEP study based on national data.

1.3.4. Studies for energy and nuclear power planning

An Energy and Nuclear Power Planning (ENPP) Study is initiated only upon official request by a Member State of the IAEA 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 for nuclear energy and its appropriate role in the national energy plan. This requires both assessment in terms of economic plans and economic comparison with alternative energy sources. The analysis methodologies MAED and WASP are used during the studies, with improvements or changes as necessary, and are released to the Member State on completion of the study.

An ENPP Study has two specific objectives. One is to work with the requesting Member State to quantify future energy requirements, consistent with both national economic development plans and the expected share of electrical energy within the overall energy needs. The study then outlines an economically optimum electrical system expansion plan, including an assessment of the need for nuclear power and its role. The second objective is to provide on-the-job training for a local team of engineers and economists who conduct the study. The Member State receives the MAED and WASP models so that further energy planning studies can be undertaken by national experts.

As such studies are carried out in close co-operation with the requesting country, a joint team of specialists in energy planning is established. This joint team includes two or three IAEA staff members familiar with questions concerning energy planning and the different models that could be used as well as specialists from the Member State, at least five or six of whom are engineers and economists well acquainted with the electricity and energy situation in the country. (It is recommended that most of them should have attended the ESEP and the ENPP training courses.) Among the national specialists is a senior co-ordinator who is able to contribute effectively to the work required and who is responsible for making contacts with various organizations within his country to obtain the information needed for the study. Although the exact content, scope and schedule of an ENPP study will vary according to the Member State, there is a well-established procedure in the conduct of such a study, which is outlined in Fig.1.1 and described in detail in the IAEA Bulletin of September 1982[1]. Section 2.3 describes an ENPP study undertaken for Algeria.

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[1] BENNETT, L.L., CHARPENTIER, J.-P., MARQUES de SOUZA, J.A., "An assessment of nuclear energy in developing countries: how the Agency can help", IAEA Bulletin 24 3 (1982) 3.

Location of Mission		at IAEA (Vienna)	OR	in the country
IAEA Mission No. 1		2 or 3 IAEA Staff Members for about 2 to 3 weeks	→	- Identification of the job - Establishing contacts - Creation of national team (4 to 6 experts) - First information and data gathering
6 months	work	Decision related to follow-up of the study First analysis of future energy demand	↔	Implementation of future programme of work Collection of missing data for energy demand analysis
Country Mission No. 1		- Analysis of first results obtained from initial data - introduction of modifications	←	Local team to Vienna (approx. 1 - 2 weeks)
3 months	work	Improvement of study on energy demand supply		Improvement of the data on energy demand and collection of input data for the electricity planning (investments) study
Country Mission No. 2		- Critical analysis of results on energy demand analysis - Set up of principal scenarios to be considered in the study	←	Local team to Vienna (approx. 1 - 2 weeks)
3 months	work	- Critical analysis of the various scenarios proposed - Start of the electricity planning study		- Discussion of the initial results on future energy demand by sector among the national organizations concerned

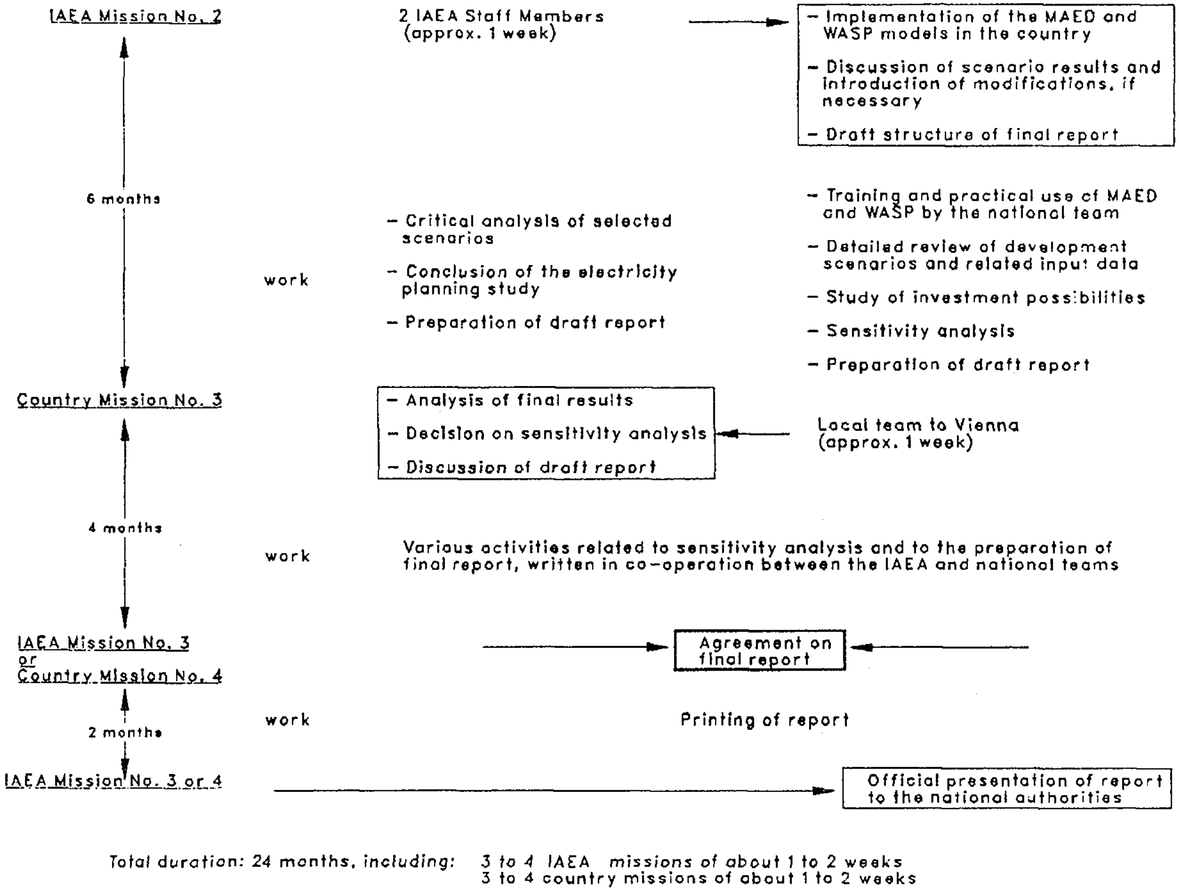


FIG.1.1. Co-operative working schedule for executing energy and nuclear power planning studies.

1.3.5. Need for long-range national planning for nuclear power

Evaluation of the economic benefits from nuclear energy in a developing country needs a broad-based and in-depth analysis of the total effect of a nuclear power programme on the overall economic development of the country. There are three main points:

(a) The development of nuclear energy in a given country cannot be evaluated in an isolated way. Nuclear technology is only one among many means to supply secondary energy (e.g. electricity and heat), and nuclear power planning should be carried out in the context of all supply options. Nuclear power planning involves evaluation of the various types and forms of energy requirements, and should take into account the country's general plans for energy and economic development.

(b) Energy, electricity or nuclear planning can be undertaken rationally only by energy specialists of the country concerned. The Agency can provide advice and some methodologies but it cannot be a substitute for the government experts who must take final responsibility for planning the development of energy supplies in their country. Training to help develop local expertise can, if required, be obtained through the IAEA training courses. The Agency strongly emphasizes that the joint ENPP Study should be carried out mainly by the national team, supplemented by assistance from Agency experts. By this approach, a trained national team will be better able to understand the situation in its own country and will be able to follow up the studies initiated in co-operation with the Agency.

(c) Finally, it must be accepted that economic studies such as those mentioned above are only a first step in the long process of nuclear power planning. Many additional studies and analyses should follow in order to determine whether nuclear power is a practical option and what would be the national implications of a decision to undertake a nuclear power programme. Complex problems such as impact on the balance of payment, financing constraints, manpower requirements, and the participation of local industry are involved; these are additional factors to be borne in mind when a country is evaluating the possibility of using nuclear energy.

1.3.6. New IAEA programmes in energy planning

In response to the need for long-range national planning, initial steps have been taken in two new programme areas: a co-ordinated research programme (CRP) and a comprehensive case study.

1.3.6.1. Co-ordinated research programme: implications of nuclear power programmes for the overall economic development of developing countries

The ENPP Studies described in the early part of this chapter focus on the direct economic and infrastructure requirements for implementing a nuclear programme; they include only limited evaluations of the impact of a nuclear programme (positive or negative) on the total energy sector and the overall economy of a developing country. However, if a more complete and realistic analysis of the appropriate role of nuclear energy in developing countries is required, then a broad-based and in-depth analysis of the total effects of a nuclear power programme on the economic development of the country is necessary.

A CRP in this domain was initiated in 1982, in which research activities in a number of Member States contribute in a co-ordinated way to two objectives:

(a) To develop a systematic procedure that can be used by developing countries to *determine the desirability and practicability of starting* a nuclear power programme;
(b) To develop a methodology that would allow those developing countries that have already decided to proceed with nuclear power development to *estimate the impacts of the programme on overall economic growth.*

Obviously, the two objectives of the research programme apply to two groups of developing countries: those that have not yet decided on the role of nuclear power in their energy system and those that have already decided to proceed with nuclear power but are only at the early stages of development. Both groups need systematic methods of determining the impact of a nuclear power programme on overall economic growth and development.

1.3.6.2. Comprehensive case study: energy supply in a developing country, including the possibility of nuclear power

The objective of the comprehensive case study, like that of the CRP, is to assess more thoroughly the energy demand and supply options, including the possible role of nuclear power, than has been done in previous ENPP studies. Such a comprehensive study would develop a long-term (25–30 years) electricity supply plan for the country and would include the following steps:

(1) Assessment and choice of development scenarios for the time horizon of the study.
(2) Analysis of associated future energy demand scenarios and the role electricity could play in meeting those demands (MAED model). The

structure of electricity demand would be studied in relation to various options, e.g. decentralized energy supplies from new and renewable sources.

(3) Review of energy demand scenarios against trends in population growth and distribution (urbanization), resource development, industrialization, etc.

(4) Economic and financial analysis of future electricity expansion plans, including the possible role of nuclear power. This would include two components: the first is a straightforward economic analysis of the electric power system, using the WASP methodology; the second and more difficult is a preliminary examination of the total capital investment and financing requirements of a nuclear power programme within the overall needs for financing national industrial development.

(5) Review of the institutional and organizational framework for the introduction of nuclear power.

(6) Review of manpower availability for the introduction of nuclear power.

(7) Review of industrial support infrastructures for construction, operation and maintenance of nuclear power projects.

(8) Development of master schedules and a programme for the introduction of nuclear power, including necessary infrastructure development.

Chapter 2

ELECTRIC POWER PLANNING AS PART OF OVERALL ENERGY PLANNING

Electrical generation system planning cannot be carried out effectively without taking into account the interactions of the energy system with the rest of the economy. This basic principle is often neglected because electrical system planning is a mature procedure while overall energy planning is at an early stage of development. The following section briefly summarizes the basic concepts of total energy system planning and its relationship to the planning of national economy and electric power.

2.1. INTRODUCTION TO OVERALL ENERGY PLANNING

It has been said that: "Plans are nothing, planning is everything." This applies especially to energy system planning. The needs that an energy supply system must meet are constantly changing; new technologies are being developed; prices of energy materials are changing dramatically in short periods of time. An effective energy planning programme is a dynamic process that is repeated periodically and adjusts to changing conditions. For the purposes of the following discussions, two definitions can be proposed:

- *The energy planning process* is the systematic assembly and analysis of information about energy supply and demand and the presentation of this information to decision-makers who must choose an appropriate course of action;
- *The energy plan* is a statement of the choices made by decision-makers at any one point in time in order to meet specific goals and objectives.

The most important concept in a definition of the energy planning process is that its ultimate purpose is to provide information to decision-makers. This distinguishes energy planning from academic and scientific studies, which are designed to improve the state of knowledge but are not aimed at decision-making.

The document referred to as the energy plan is simply a statement of the choices made. It is not an unswerving statement which, once issued, is not subject to change. It is rather an evolutionary document that is revised periodically as conditions change. Many countries do not have a single document that can be termed an energy plan. Instead there are a series of laws, policy statements, energy project construction programmes and the like which constitute an equivalent energy plan even though they are not compiled in a single report. The concept of the 'plan' as a statement of choices is nonetheless the same.

There are several things that energy planning should *not* be. Energy planning should not be an end in itself. The interminable conduct of studies and preparation of planning documents that are not implemented is a futile exercise and a waste of valuable human resources. Energy planning should not be an excuse for inaction. Deferring action pending the preparation of a plan is acceptable only to a point. Continuing inaction may lead to consequences that are worse than taking action in the absence of a systematic analysis. Finally, planning should not be a substitute for decision-making. Difficult decisions and choices must be made in order to implement an energy programme. The energy planning process can only assist by making information available to decision-makers.

A systematic approach to energy planning includes a number of steps, such as:

(1) Defining the goals and wider objectives of the plan,
(2) Determining the approach to be taken,
(3) Identifying the information required from the planning process,
(4) Choosing the analysis process,
(5) Conducting the analysis,
(6) Presenting the results to decision-makers,
(7) Preparing the energy plan.

These steps can all be seen as part of a dynamic planning process. Each step may be performed several times before proceeding to the next. Each may be revised as information from succeeding steps becomes available. (Each step is discussed in the following subsections.)

2.1.1. Basic goals and wider objectives of the energy plan

The energy plan can have several basic goals and wider objectives, depending on the needs and situation of the country. These goals and objectives may be set by individual companies if the energy sector is privately owned, or they may be set by the government if the energy sector is publicly owned. In most countries there is a mix of both public and private ownership and the goals and objectives reflect this situation. Three basic goals can be identified for all situations:

- To prepare the capital investment programme that will lead to construction of energy facilities,
- To develop appropriate government policies influencing the development of the energy system,
- To provide signals to appropriate industries and institutions as to the directions that will be taken in the future.

Preparation of the capital investment programme is probably the most important goal of the energy plan since it represents the most substantial commitment of financial and human resources. This goal is most critical in countries where the government owns and operates large segments of the energy industry. In these cases, the energy plan becomes the investment programme for the government, by means of which the government is deciding whether to invest in electric power plants or in refineries, in pipelines or in coal-handling ports. Since the government must consider the requirements of the entire energy sector, the investment plan must be complex and comprehensive. In countries where there is significant private ownership of energy industries, each energy company prepares its own capital investment programme. Collection of these separate investment programmes constitutes an equivalent energy plan that meets the first goal.

The second goal of the energy plan is to develop government policy regarding the energy sector. This applies to countries both with and without private ownership of energy industries. The policies contained in the energy plan include laws, regulations, tax incentives, subsidies and other government actions affecting the energy system. Energy pricing is one of the most important policies in the plan. Under ideal conditions, the set of policies is consistent and reflects a definitive policy direction. In reality, government energy policies are developed at different points in time and may even be contradictory. Obviously, the energy planning process can help to identify these inconsistencies and propose appropriate modifications.

The third goal of the energy plan is to give information (i.e. signals) on future directions to the appropriate bodies, such as energy industries, equipment suppliers, and institutions for manpower development. This is an important part of the plan since energy projects often require long lead times and advance preparation. An energy plan can help provide these organizations with insight into how to prepare for future developments.

The wider objectives of the energy plan are less easy to categorize than the basic goals. They are much more diverse and are sensitive to the needs of a particular country. It is, however, important for energy planners to attempt to arrive at a statement of objectives before proceeding into extensive analysis. Reaching such a consensus will reduce inefficiency, focus attention on the key issues, and help organize the efforts of the participants in the planning process.

The following examples illustrate the statement of wider objectives of the energy plan:

- To develop the energy supply system leading to lowest cost to consumers,
- To maximize reliability and safety in the energy supply system,
- To develop a diversified energy supply system with less dependence on imported oil,
- To maximize the use of indigenous energy supplies,
- To maximize the use of renewable resources,
- To provide energy for optimum industrial development,
- To reduce the use of non-commercial fuel and subsequent deforestation,
- To minimize environmental effects.

There are many more potential objectives. The actual statement of objectives may be a combination of some of these and may include statements of conditions that constrain the achievement of objectives. The objectives can sometimes conflict with each other, and objectives, once stated, are therefore subject to change as more information is available. For example, the objective of maximizing the use of indigenous resources may prove too costly to achieve and may be modified to reflect actual conditions.

It is especially important for energy planners in general, and electric system planners in particular, to recognize that their objectives are only a part of overall national objectives. The energy system is only a part of the national economy and the electric system is only a part of the energy system. The objectives stated for the energy system should reflect the conditions of the rest of the economy. This is especially true where there is a national economic plan but also applies when there is a market-based economy. Electricity and other forms of energy do not exist independently; they are only services that assist the conduct of other economic activities.

2.1.2. Approaches to energy planning

The second step in the energy planning process is to determine which approach should be taken to meet the basic goals and wider objectives of the plan. The choice of approach involves four major decisions: the scope of the plan, the scale of the plan, the time horizon and the level of detail.

The scope of an energy plan determines what components of the energy/ economy system will be included in the energy planning process and in the energy plan itself. The widest scope includes a global analysis to determine the world markets for goods and services produced and consumed by the country. In an energy perspective, this is especially important for countries that are major exporters of energy. The total national economy is another level in the scope of the energy planning process. It is almost impossible not to include some aspect of the national economy in any energy plan. To fail to include it would be to ignore the fundamental interaction between economic growth and energy requirements. The entire energy system is the scope of a national energy plan; the entire electric system is the scope of a national electricity plan. The narrowest scope used in energy planning is an individual energy project. Independent of the scope chosen for the energy planning process, it must be recognized that the issues at stake in both broad and narrow scope interact extensively. This cannot be ignored in any planning procedure.

The scale of an energy plan determines the required spatial disaggregation. National energy planning procedure provides insight into the energy requirements of the country as a whole. Regional or site-specific analyses are often required in addition to a national analysis in order to account for local conditions that would otherwise be overlooked. For example, a national energy evaluation may indicate that renewable resource technologies are not cost-effective, whereas local analysis may reveal areas where such technologies are very cost-competitive. Although national perspectives are most often used in an energy planning process, it is important not to neglect regional and local effects.

The time horizon chosen for an energy plan is an important factor in determining the methods to be used and the value of the results. Most energy plans, especially electric system plans, are carried out over a long-term planning horizon (20–30 years). This is because of the long lead times required for the design and construction of energy facilities. Most national economic plans are for much shorter periods (typically five years). Long-term energy planning analyses must recognize this disparity. The results of energy planning must provide information on those actions that must be taken in the short and medium term to realize the long-term objectives. Another aspect of the time horizon issue is that different analytical tools must be used for short-term and long-term planning issues. It is not possible to apply the same analysis procedure to develop information for day-to-day operational decisions as for 20–30 year decisions.

The level of detail in an energy plan is most closely related to the time requirements for decisions. Frequently, the need for a rapid decision on some energy issue precludes the use of an in-depth analysis, and a 'quick-and-dirty' procedure must be used instead. Such procedures can be an important component of an energy planning process if their limitations are recognized by planners and decision-makers alike. Analyses conducted in one week can help to give a rough insight into energy issues but should not be expected to provide the same comprehensive insight as analyses conducted in one year. In the course of time the energy planning process in a country should develop to the point of being able to provide reasonably comprehensive information for decision-makers relatively quickly, but there will always be a need for 'quick-and-dirty' procedures to complement the in-depth methods.

2.1.3. Information required from the planning process

When the basic goals and wider objectives of the energy plan have been stated and the approach to the planning process has been decided, the next step is to identify the information required. The purpose of the energy planning process is to provide information for decision-makers, and two distinct types of information are involved in energy planning: detailed technical information and decision-making information.

Detailed technical information is required by energy planners (engineers, geologists, economists, etc.) in order to conduct analyses and evaluate the technical and economic viability of alternatives. Such information includes thermodynamic efficiency of energy systems, capital and operating costs of energy technologies, reliability and performance characteristics of systems, geological parameters of resource areas, macroeconomic parameters of the national economy, etc. This information is essential for the conduct of any analysis to do with the energy system.

A different set of information is required by senior decision-makers, who are usually not as technically oriented as the energy planners. This is an important distinction since an informed choice of which energy programme to pursue is based on the quality of the information presented to decision-makers. If the information is too technical, too detailed, or in a form that is unintelligible to decision-makers, then the most sophisticated analysis can provide little useful information, a fact that is often overlooked in the conduct of an energy planning analysis.

A simplified statement of the basic information required by decision-makers can be expressed by the following questions:

(1) What are the energy requirements for the country's economic development?
(2) What energy supplies are available to meet the demand?
(3) What resources (money, labour, materials, etc.) are required to build and operate the required energy system?
(4) What alternatives are available and what are the impacts of the alternatives?

There are countless variations to these fundamental questions but the thrust is basically the same.

The first question deals with the needs that the energy system must fulfil. If the country is to achieve a desired level and pattern of growth, the energy requirements of that growth must be known. It must be recognized that certain types of growth may not be possible because of energy constraints. Decision-makers must be aware of the nature and magnitude of these difficulties. The answer to the first question is fundamentally a demand analysis.

The second question tries to identify potential sources of energy. These include domestic reserves, import opportunities and energy technologies (conventional, renewable, advanced). In answering this question, the energy planner is determining the different paths that the country might take in meeting its energy needs. Decision-makers must be made aware of the different courses of action open to them in arriving at a choice.

The third question is often the most significant in the decision process. It attempts to determine what a particular course of action will cost. In answering this question the planner must deal with more than financial costs. Effects on the environment, infrastructure development, and social acceptability are some of the other 'resources' that the energy system will consume. These must be evaluated and presented as part of the decision information.

The fourth question tries to provide decision-makers with information on alternatives. It is not possible to choose a particular course of action (an energy facility construction programme, a set of energy policies, etc.) without knowing what else is possible and comparing alternatives. The first three questions also concern alternatives but the last one focuses attention on alternatives for the overall energy system. For the special conditions of electric utility evaluations, planners generally

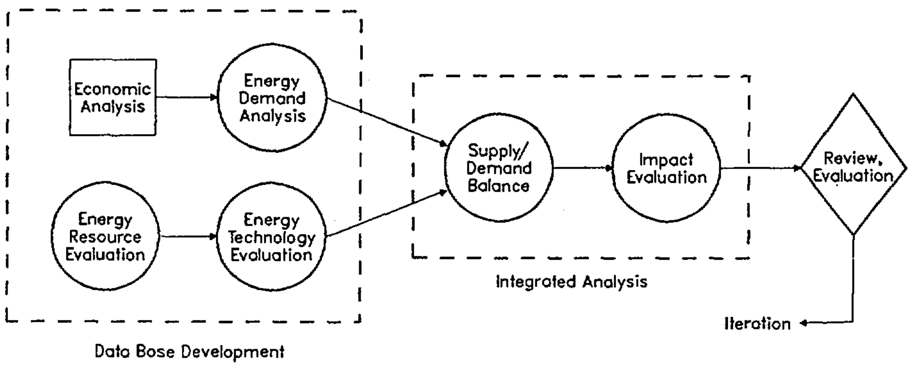


FIG.2.1. Typical sequence of tasks in energy planning.

use four key criteria against which to compare possible alternatives: economic viability, technical feasibility, environmental acceptability and financial security.

2.1.4. The analysis process

The fourth and fifth steps of energy planning – the choice of analysis process and the conduct of the analysis – are heavily dependent on the situation and needs of individual countries. Attempts have been made to outline a specific analytical procedure that would apply to all developing countries, but such a procedure cannot be developed because of the wide range of conditions and requirements in energy planning. Developing countries are not a homogeneous group and therefore cannot all be analysed by means of the same techniques. Section 2.3 illustrates some of the different approaches to planning and demonstrates the variations in technique.

Despite the range of possible analytical approaches, energy planning studies all have some common elements, which can be seen as tasks necessary for the completion of an energy analysis. The analytical technique chosen, the order in which the tasks are performed, and the method of integrating the results of the different tasks may vary considerably, based on the needs of the country. Nevertheless, the set of tasks represents a framework in which to view the activities necessary for energy planning. Figure 2.1 shows a typical sequence of tasks that should be included in an energy analysis.

The tasks are basically divided into two groups: the *data base development* and the *integrated analysis.* The database development is designed to assemble all the necessary information required to conduct an energy analysis. Because of the diversity and the large amount of information needed, this is not a minor undertaking. The integrated analysis is designed to structure the data into a consistent format that allows the planner to evaluate alternative scenarios. There is also a reviewing and evaluating procedure. Several iterations may be required as the results of the analyses become available.

Certain difficulties have been encountered in the database development in virtually all energy studies in developing countries. Data are often either non-existent, of unreliable quality, or extrapolated from developed countries and so bear only marginal relation to conditions in a developing country. There are several ways to deal with such problems. The first is to do nothing. This is an admission of defeat and so precludes any further work. Despite the apparently unacceptable nature of this course, it is frequently chosen. The second method is to invest in a data collection programme. This is clearly the preferred choice where information is so poor that no reasonable analysis can be made. This course requires a commitment of time and resources and will postpone the completion of an overall energy analysis. In many circumstances, it is nevertheless the only practical way to proceed. A third course of action is to assemble the best available set of data and conduct the analysis recognizing where the weaknesses are. This method is chosen when time does not permit an extended data collection programme. If the weak spots in the data are kept in mind as the analyses are made and if efforts are made to improve the data for subsequent analyses, this can be a useful method.

Section 2.2 discusses in more detail the individual tasks in both the data base development and the integrated analysis.

2.1.5. Presentation of results

One of the most neglected and perhaps one of the most important aspects of the energy planning process is the presentation of the results of the analysis to decision-makers. The differences in political and administrative structures in developing countries make it impossible to describe a generic method for planners to present information to decision-makers. In one country the process may involve presentations to senior officials in which analytical results are described and factors influencing decisions presented. In another, there may be extensive public participation in the decision-making process through hearings, open meetings and other forums. Whatever the mechanism, there are several aspects of the decision-making process that planners must consider when presenting the results of their analyses. First, the decision-maker is generally less technically trained and experienced than the analyst. Presentation of information that is beyond the technical comprehension of the decision-maker does little to help in choosing a course of action. Section 2.1.3 illustrates the different information required by decision-makers and analysts.

A decision on the energy system is based on a multitude of factors, not all of which the analyst can include in the energy planning study. Political considerations, public pressure, international relations, etc., often influence an energy decision as much as any analytical results, if not more. The energy planner must recognize this and be prepared to accept the fact that the recommendations which logically result from a study may not always be chosen. In such circumstances, the astute energy planner should be able to provide decision-makers with an evaluation of the effects of an alternative choice. Should a course of action be chosen on the basis of some non-analytical factor, the good energy planner can tell the decision-maker some of the effects (e.g. costs, labour requirements, energy availability) of that choice.

Finally, because of the complex nature of energy issues and the divergent opinions on analytical methods and data, energy planners are often accused of developing any result they desire by manipulating assumptions, analysis procedures, data, etc. Certainly an analyst must make certain decisions that affect the outcome of an analysis. However, an analytical result is of value to a decision-maker only if it represents the best available technical judgement. Even if the decision-maker disagrees with the recommendations, the analysis is valuable in that it shows the implications of the course taken. Energy planners must take pains to conduct their analyses without biasing the results in favour of any particular point of view (e.g. preferring one particular technology to another). It is the role of the decision-maker, not the analyst, to include non-technical factors in the decision process; the analyst must provide the best possible technical information to assist in this process.

2.1.6. Preparation of the plan

When all the steps of the energy planning process have been completed, reviewed, iterated and re-evaluated, the culmination of the exercise is the preparation of the energy plan. Remember that the plan is a statement of the choices made and is itself subject to periodic review and revision.

No one format can serve as the basis for all energy plans; each must be tailored specifically to the needs at hand. The plan should contain the following basic elements:

- A statement of the basic goals and wider objectives of the plan,
- A statement of the current energy situation in the country,
- A discussion of possible growth alternatives for the country and the energy demand implications of these alternatives,
- A review of possible courses of action which were considered and analysed as part of the energy planning process,
- A statement of the choices made in terms of projects to be built, policies to be implemented, and additional studies to be undertaken,
- A statement of the steps to be taken to implement the plan.

This format can be used to satisfy the goals of the energy planning process.

2.2. ENERGY PLANNING PROCEDURES

Section 2.1.4 above and Fig.2.1 describe a typical structure of an energy planning analysis. Electric system planning is an integral part of this overall analytical procedure and uses much of the same information that is developed in a comprehensive energy analysis. It is therefore important that the electrical system analyst understand the scope and approach of the analytical procedures used in comprehensive energy studies. As has been stated several times, it is not possible to prescribe a single analytical procedure that is usable in all developing countries. This section presents some alternative approaches to energy analysis. The choice of approach depends on the needs to be met.

2.2.1. Economic analysis

Figure 2.1 shows that economic analysis is the first step in the energy analysis; it is the basis for both comprehensive energy planning and electricity planning. The pattern of economic development is what determines the need for energy. Likewise, the price and availability of energy and electricity can shape economic growth. The nature of economic growth in developing countries is the subject of countless theoretical arguments and divergent opinions. Energy and electricity planners often rely on economic analyses performed by other groups and so use the results without being fully cognizant of the theoretical basis of the analysis. Nevertheless a number of economic analysis issues must be considered by energy planners.

2.2.1.1. Energy and gross domestic product (GDP)

Following conventional economic theory, it is reasonable that total energy use in a country would rise with increases in production and income. This seemingly self-evident proposition is borne out by a comparison of energy consumption and broadly defined measures of economic activity. The most common measure of aggregate output is GDP, which measures in money units the value of all newly produced goods and services from a given economy. Figure 2.2 plots the levels of per capita energy use and GDP for several countries. For both developed and developing nations there has been an apparently good correlation between these two variables. Nevertheless, increase in economic performance across nations is not always associated with the same level of increase in energy consumption. Japan, for example, uses 12 MJ per dollar of GDP, while the USA and Canada use about 25 MJ and 32 MJ respectively per dollar of GDP. Sweden has a per capita GDP that is 16% higher than the USA but the USA uses about 35% more energy per capita.

The relationship between aggregate economic activity and electrical energy demand has been quite different in the case of electric system planning from

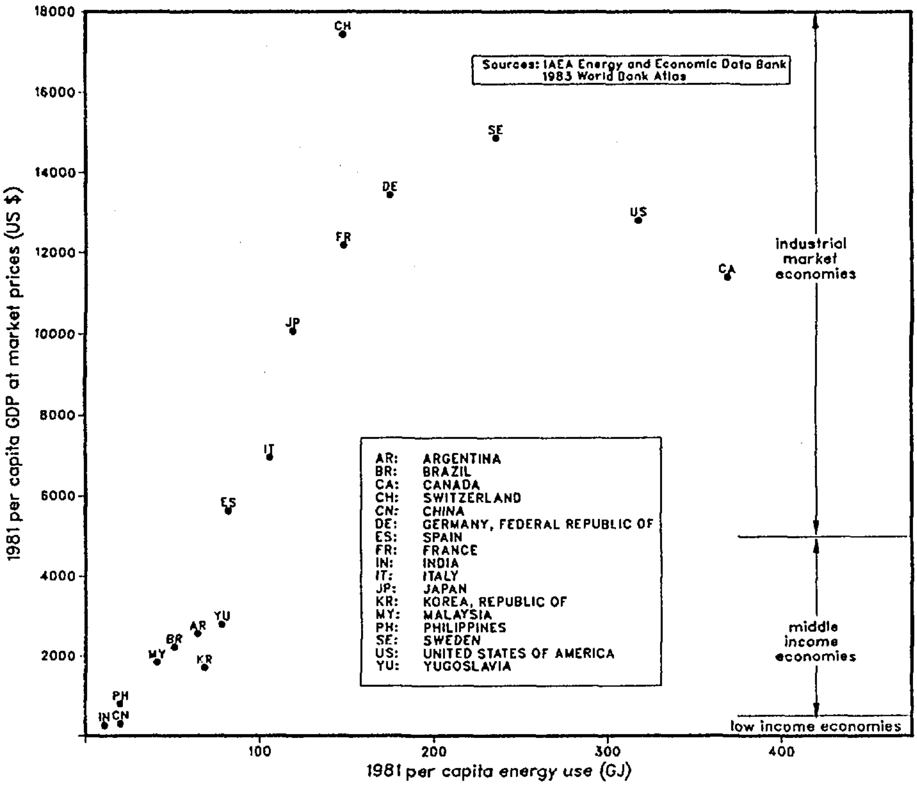


FIG.2.2. Relation of GDP to energy consumption (both in per capita terms).

the case of overall energy demand. For several decades before 1973, the demand for electrical energy grew more rapidly than the demand for total energy. While the growth in total energy demand slowed considerably after 1973, electrical energy demand was only slightly deflected from its historic growth path. Figure 2.3 shows this quite well by comparing the per capita growth rates of total energy, electrical energy and non-electrical energy relative to the growth of GDP in six developed nations. The growth in non-electrical energy relative to GDP dropped sharply after 1973, while average growth of electrical energy relative to GDP was generally much the same from 1960 to 1980.

From cross-sectional data of many countries at various stages of economic development, it can be seen that the energy/GDP relationship is not fixed as might at first be expected. It differs widely even among nations with similar economic conditions. Moreover, a nation moving through various stages of development – from an agrarian to an industrial to a post-industrial service economy – will have a quite different level of energy use per unit of output.

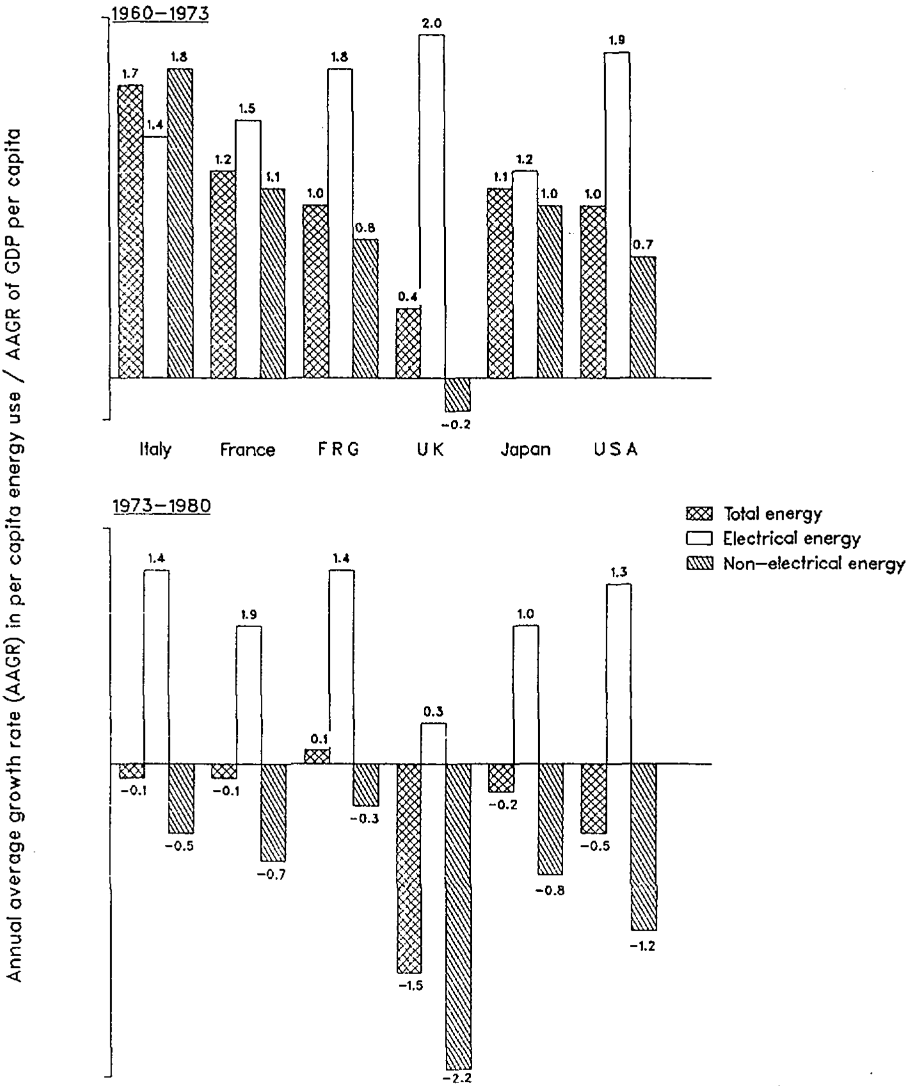


FIG.2.3. Electric and non-electric energy growth rate relative to GDP growth rate (from [1]).

These types of developmental shifts typically take decades or even lifetimes to accomplish, so they may have little relevance to the system planner concentrating on the next 10–20 years.

Analysis of the relationship between energy and GDP across time for a particular nation has usually resulted in higher correlations than cross-sectional comparisons among nations. However, since 1973, even these relatively good correlations have grown less precise and stable. For example, simple linear regressions of total energy use against GDP for the USA for two different periods are:

1965–1973:

$$\text{Total energy consumption } [10^{18}\text{ J}] = -10.96 + 74.25 \times \text{GDP } [10^{12}\text{ US \$}]$$

$$\text{Correlation coefficient: } R^2 = 0.92$$

1973–1981:

$$\text{Total energy consumption } [10^{18}\text{ J}] = 60.49 + 13.83 \times \text{GDP } [10^{12}\text{ US \$}]$$

$$\text{Correlation coefficient: } R^2 = 0.37$$

These results are also shown in Fig. 2.4. Note that the slope of the regression line is substantially lower after 1973, indicating that fewer units of energy are needed to produce a given amount of GDP. Also, the R^2 correlation coefficient is substantially lower, showing that the simple linear relationship no longer explains the energy-to-GDP relationship so well. The same type of changing relationship can be seen in many developing countries.

It must then be asked whether these aggregate relationships between GDP and energy consumption can be of use in energy and/or electric system planning. Simple linear models using these variables once quite accurately predicted energy needs, but they no longer do so. Since 1973, when the relative value of energy increased, the use of energy has shown major changes from historical trends. It must be concluded that a simple energy/GDP projection should not be used except in extreme circumstances where no other measure is available.

2.2.1.2. Energy and the macroeconomy

Numerous methods are available to analyse the growth of the macroeconomy for use in energy and electricity planning. Among the most frequently used techniques are trend extrapolation, input/output analysis, and econometric analysis. These procedures are all designed to develop projections of how the country's economy will grow in the future. Such projections are expressed in terms of value added or output of each sector of the economy. It is important to recognize that the projections are stated either in financial units (e.g. dollars of value added) or in physical quantities (e.g. tonnes of steel produced). They are not expressed in energy units. The conversion of these economic projections to energy demand projections is a separate step in the analytical process and is discussed later.

The most direct method of developing an economic projection is to use trend extrapolation or a time series analysis. To carry this out, it is assumed that a particular economic variable (e.g. GNP, production of steel, personal income)

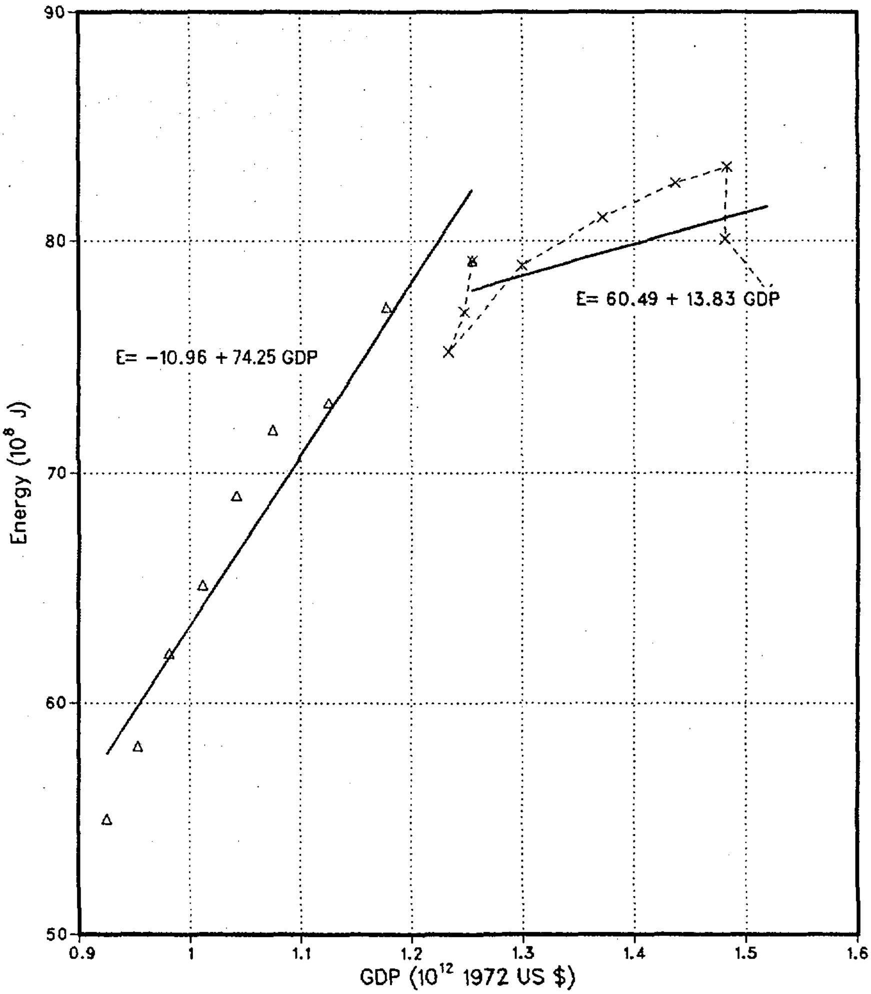


FIG.2.4. Relationship of energy consumption to GDP for the USA 1965–1981 (from [2, 3]).

behaves cyclically. Future values of the variable can be estimated based on past behaviour. Expressed in equation form:

$$Y_T = A_0 + A_1 Y_{T-1} + A_2 Y_{T-2} t \ldots + A_N Y_{T-N} + E_T \tag{2.1}$$

where Y is the variable of interest, T is the time period, A_ℓ are coefficients estimated by regression analysis, and E_T is an error term to be minimized in the regression. In this case the value of the variable in a future time period depends only on its past behaviour.

This type of economic forecasting technique is valuable in that it is relatively easy to implement, the trend and cyclical behaviour of the variable are easily identified, and it can be directly correlated with historical performance. A disadvantage of the method is that it assumes future behaviour of the variable will parallel past performance. In this regard it is good for only short-term evaluations and cannot capture long-term changes. The future performance is also based only on the variable itself; there are no independent variables to enter the analysis. Some work has been done to include one or two additional variables in this type of study but the complexity increases rapidly. Other more sophisticated techniques become attractive if the complexity increases too much. Another weakness of particular significance to developing countries is that there are frequently insufficient historical data on which to base a good time series analysis.

Another kind of economic forecasting technique is the input/output model. In this approach a matrix of industrial interactions is developed for a given year. The matrix records the purchases of each industry from all the other industries in the economy. It is thus possible to determine that an increase of one unit of production in the automobile industry (for example) will require a proportional increase in the output of the steel industry, the glass industry, the plastics industry, etc. By forecasting the level of final demand, the input/output procedure can produce a consistent picture of how that demand 'ripples' through the entire economy.

The input/output methodology is especially attractive because its results are, by definition, internally consistent. Also, it provides a detailed sector-by-sector picture of economic activity which is especially useful to energy analyses. The procedure has a number of weaknesses, however: it takes a very great effort to assemble a base year input/output matrix. Very often the data do not become available for 5–10 years after the year of study. The future projections are based on fixed input/output coefficients which may, in fact, change significantly in the long term (for example, new cars can be made with more plastics and less steel, thus changing the interaction between the industries and the resultant energy demand). Methods have been developed to modify the input/output coefficients but these are not well validated. The methodology still relies on an exogenous projection of final demand; the planner has still to develop a way of making this projection.

A third type of economic forecasting technique is the econometric approach. In this method the variables of the economy are related through a set of simultaneous non-linear equations which relate all the variables in the economy to each other and to exogenous factors. The description of the economy can be as simple or as complex as desired.

Econometric models are the models most often used in economic analysis. They are based on defined economic theories; they can explicitly describe causal relationships in the economy; they provide simultaneous feedbacks among the various parameters; and they allow for direct study of policy alternatives (e.g. fiscal policy, tax structure). However, these models are difficult to develop, maintain and use, and a sophisticated analyst staff is required to implement the techniques properly. Decision-makers often find them hard to understand. They require an aggregation of variables (and subsequent loss of sectoral detail) if the equations that must be solved simultaneously are to be kept to a manageable number.

Irrespective of which economic analysis technique is chosen, the most frequently used procedure is to develop a set of economic growth scenarios reflecting different possible paths the economy may take in the future. This is one method of dealing with the uncertainty inherent in forecasting the economic future, particularly over the long periods (20–30 years) used in energy planning. The scenarios chosen should represent a reasonable range of probable developments and should establish the bounds within which the economy can be expected to grow. In this way the planner can determine the range of possible requirements that will be placed on the energy system.

Because of the strong interrelationship between energy and overall economic growth, this type of economic projection analysis must make some assumptions about the price and availability of energy. This presents a dilemma to planners because the energy planner cannot provide a good estimate of energy costs until he knows the size of the demand that economic growth will place on the energy system. Likewise, the economic planner cannot provide a good estimate of growth without knowledge of energy costs. To break into this interdependent loop for analysis purposes, one usually starts with a rough assumption of energy costs. This is used in an initial economic analysis to project the pattern and extent of growth. These economic projections are then used to analyse the demands placed on the energy system and to re-estimate the cost of energy. If necessary, the economic projections are then revised and the energy analysis performed again with the new projections. This type of iterative procedure is used throughout the energy planning process.

2.2.1.3. Sectoral economic analysis

In addition to macroeconomic analyses, other studies are made to evaluate growth potential in other parts of a country's activities. These sectoral analyses are an important component of the economic analyses required for energy planning. The sectors which are usually studied include industry, agriculture, transport, and residential, commercial and rural communities. All are important energy users and should be included in energy studies. Analyses of the growth potential in each of these sectors are often carried out by separate planning groups located in separate government organizations. These analyses often focus only on the unique aspects of each sector and do not represent an integrated analysis of development. In theory, all these sectoral analyses should use common assumptions and should be co-ordinated with the macroeconomic analysis previously described. In practice, it is very difficult to achieve this level of co-ordination and consistency. The energy planner may be presented with a macroeconomic analysis and a set of sectoral analyses that are inconsistent and based on different fundamental assumptions. Often the energy planning process provides the impetus to bring these various studies together and to arrive at a consensus on the assumptions that will be used for analysing future growth.

Industrial sector studies are especially important to energy planners since industry is usually the biggest consumer of energy and electricity. Industry studies are often made for individual industries and subsectors (e.g. iron and steel, cement, textiles). This causes a co-ordination problem since the subsectors are so diverse. Industrial sector studies are rarely done on the long-term (20–30 years) planning horizon used for energy planning. Consequently, the macroeconomic analysis is most frequently used to provide long-term insight into industrial growth, while the industrial studies are used to identify changes in industrial processes and technologies.

The agriculture sector is generally not a large energy consumer since much of its energy requirement (fertilizer, food processing, etc.) is treated as part of the industrial sector. Nevertheless, in developing countries agricultural trends toward mechanization and requirements for irrigation water pumping represent a significant demand on the energy system. Sectoral studies in agriculture are therefore a significant part of the energy planning process.

The transport sector is usually one of the best developed with respect to planning since transport infrastructure development requires long lead times and extensive planning. Since transport energy requirements are a function of passenger and freight activity, the macroeconomic analysis described above provides only limited insight into possible energy requirements of the transport system. In general, a transport analysis uses a macroeconomic analysis as its primary input (in much the same way as an energy analysis does) and then proceeds to estimate passenger and freight travel demand. An energy analysis of the transport system has to use the same approach.

The residential and commercial sectors use energy in similar ways (lighting, space heating, water heating, cooking, electrical appliances), but the demands are driven by different parameters. Commercial activity is closely related to general business activity and so can be analysed by the macroeconomic approach. Residential growth is driven by population growth, household formation, residential construction and personal income. These parameters are usually analysed by procedures other than macroeconomic studies and must be treated separately in an energy analysis.

Rural communities are an important component of energy studies since they represent a large section of the population in developing countries and are a significant consumer of energy. Rural communities are a microcosm of an entire national economy in that they represent all sectors of economic activity (industrial, agricultural, residential, commercial, transport) in one small geographical area. A complicating factor in the analysis of rural communities is that much of the energy is provided by non-commercial sources (firewood, agricultural waste, animal dung, etc.) and is difficult to analyse by traditional market economy techniques. Data on rural community energy consumption patterns are virtually non-existent in many developing countries. Nevertheless, these communities represent a significant 'potential demand' for commercially supplied energy and must be included in an energy analysis.

2.2.2. Developing energy demand projections

Macroeconomic and sectoral economic analyses provide the basic levels of activity that will determine the demand for energy. Remember that these analyses provide information expressed in terms of economic or physical quantity (e.g. dollars of value added, tonnes of steel produced, passenger-kilometres travelled, number of dwelling units). As shown in Fig. 2.1, the next step of the energy analysis is to convert these activity projections.

One of the most frequently used methods of developing energy demand forecasts, since it is a simple procedure and requires only the minimum amount of data, is to relate the current fuel and electricity consumption to the economic activity and apply the economic growth rates to the energy use. This procedure is not recommended for long-term analyses, however, as it does not allow the planner to take into account developments such as fuel-switching, improvements in technology, and market influences on energy demand. To describe an alternative approach requires some additional definitions:

> *Energy consumption* is the fuel and electricity delivered to consumers; it is the quantity of energy that the consumer (an industrial plant, a household, a shop, etc.) is billed for by a supplier.
>
> *Useful energy demand* is the actual energy used by the consumer to perform a useful function (e.g. provide heat, motive power, lighting); it represents the energy output of a conversion device (boiler, furnace, water heater, etc.); it differs from energy consumption by the efficiency of the conversion device.

The concept of useful energy demand allows for the analysis of fuel substitutions (different fuels being used to meet the same useful energy demand), technology improvements (increased efficiency of conversion devices), and process changes (e.g. changing an industrial process to use less useful energy per unit of product output). Table 2.I lists typical useful energy demand categories for each sector. Each category can be subdivided to treat special problems; for example, industrial direct heat can be divided by temperature range to allow the analysis of potential penetration of low-temperature solar systems. The useful energy categories can also be aggregated for a simplified analysis. Note that electricity can be considered a separate useful energy demand category. This applies to situations where electrical energy cannot be readily replaced by other fuels (e.g. lights, electro-

TABLE 2.I. TYPICAL USEFUL ENERGY DEMAND CATEGORIES

Sector	Categories	Comments
Industry	Indirect heat	Boilers to provide steam.
	Direct heat: Using any fuel Using clean fuel High temperature Medium temperature Low temperature	Furnaces, kilns, dryers, etc. Clean fuel use required by some processes to prevent product contamination. Temperature differences allow for analysis of possible solar system penetration.
	Process electricity	Certain processes where electricity must be used (electric arc furnaces, aluminium smelting, etc.).
	Other electricity	Lights, motors, pumps.
	Motive power	Heavy machinery (internal combustion, electric).
	Feedstocks	
	Vehicles	Off-road industrial vehicles.
Agriculture	Same distribution as industry	
Residential/ commercial	Space heat/air conditioning Water heat Cooking Lighting	Can be electric or direct fuel.
	Electromechanical	Appliances.
Transport	Passenger travel: Automobile Bus Rail Air Freight travel: Truck Rail Marine Air	Intra- and inter-city. Domestic, international.

mechanical devices, industrial process electricity). In other categories (e.g. space heating, water heating) electricity is an energy source competitive with other fuels.

The process of using this information to make energy demand projections is illustrated in Fig. 2.5. *The first step* is to assemble data on current energy consumption, i.e. fuel and electricity. This information should be disaggregated by

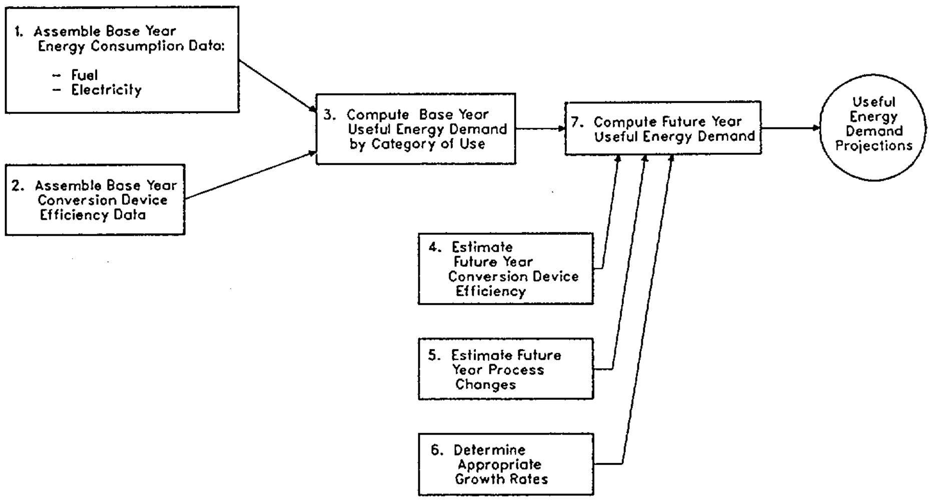


FIG.2.5. Typical energy demand forecasting procedure.

each of the demand sectors (e.g. industry, agriculture, transport) and may be disaggregated by subsector if desired. These are fuel-use data and can be measured by customer bills, fuel distributor records, etc. An important part of the data assembly is determining the quantities of this energy that are used for different purposes. For example, in considering industrial use of fuel oil, the information required includes the total quantity used and the portions used by boilers (indirect heat), furnaces (direct heat) and other systems. This level of detail can often be obtained only by surveys and on-site visits since it is rarely available as part of routine record keeping.

The second step is to assemble data on base year conversion device efficiencies. A set of information generally used in planning studies is available from several sources [4–6]. A more accurate way of determining this is to conduct spot surveys of actual equipment in place in the country. This is a fairly effort-intensive activity and requires measurements of equipment performance. A carefully designed sampling program, including the recording of surrogate data, is required in order to avoid a great deal of wasted effort.

The third step is to estimate the base year useful energy demand. The general equation is:

$$\begin{bmatrix}\text{Base year}\\ \text{useful energy}\\ \text{demand}\end{bmatrix} = \begin{bmatrix}\text{Base year}\\ \text{energy consumption}\end{bmatrix} \times \begin{bmatrix}\text{Base year}\\ \text{conversion device}\\ \text{efficiency}\end{bmatrix} \qquad (2.2)$$

The data for the right-hand side of Eq. (2.2) come from steps 1 and 2 above. The base year useful energy demand should be computed in as disaggregated a manner as the data permit.

The fourth step is to estimate the improvements in conversion device efficiency over the planning period. For example, it may be estimated that current oil-fired boilers are operating at 50% efficiency and that new boilers utilizing waste heat recovery systems could function at 70% efficiency. The sources of information on these improvements are the energy conservation technology studies conducted in the USA, Europe, Japan and several developing countries. Equipment manufacturers are another source of information.

The fifth step is to determine where process changes in future years will result in a different useful energy demand per unit of output. One example would be the shift from the wet to the dry process in cement manufacture; another would be mode shifts in the transport sector. These changes will alter the useful energy requirements above and beyond any changes resulting from equipment efficiency improvements.

The sixth step is to determine which growth rates from the macroeconomic and sectoral economic analyses are appropriate to each demand category. For example, growth in direct heat requirements in the cement industry may be tied to the growth in value added in this industry as projected by the macroeconomic analysis. Growth in residential space heating demand may be tied to household formation or to housing construction. All the basic economic parameters for this analysis should be derived from the macroeconomic and sectoral studies.

The final step is to apply the information to make a projection. The basic equation is:

$$\begin{bmatrix}\text{Base year}\\ \text{useful energy}\\ \text{demand}\end{bmatrix} \times \begin{bmatrix}\text{Effective}\\ \text{change resulting}\\ \text{from process changes}\end{bmatrix} \times \begin{bmatrix}\text{Economic}\\ \text{growth}\\ \text{parameter}\end{bmatrix} = \begin{bmatrix}\text{Future useful}\\ \text{energy demand}\end{bmatrix} \tag{2.3}$$

The projections of useful energy demand from Eq. (2.3) are the basis for the subsequent analysis of supply and demand balance. Separate projections should be prepared for each economic scenario studied in the macroeconomic analyses.

When the appropriate mix of fuels used to satisfy the useful energy demand is determined, it is converted back to fuel and electricity consumption requirements using the future year efficiency:

$$\begin{bmatrix}\text{Future energy}\\ \text{consumption}\end{bmatrix} = \begin{bmatrix}\dfrac{\text{Future useful energy demand}}{\text{Future year conversion device efficiency}}\end{bmatrix} \tag{2.4}$$

Tying the useful energy demand forecasts to economic activity parameters is a more reasonable way to project energy requirements than just making fuel-use projections. Useful energy is more closely correlated with economic activity than is energy consumption because the parameters of conversion device efficiency and fuel choice are accounted for separately. This is the method of choice whenever data and resources permit. It is one of the fundamental demand analysis methods employed in energy planning studies. Demand projections are, however, often made separately for electricity and each of the relevant fuels (e.g. oil, gas, coal). Chapter 4 deals with methods for electrical load forecasting; in principle, the techniques are analogous to those described here, i.e. the load forecast is driven by an economic forecast tied to a description of current electricity consumption patterns.

2.2.3. Resource evaluation

Figure 2.1 shows that there is another set of activities in the database development distinct from the demand analysis. The first activity in this set is the resource evaluation, which focuses on the determination of the energy resources available to a country. For convenience, the resource evaluation is described for non-renewable energy sources only. The renewable energy sources are described in Section 2.2.4. The reason for this split is that the resource evaluation discussed here is primarily a geological assessment. For renewable resources, the evaluation is primarily an engineering assessment and is therefore treated as part of the technology evaluation. The energy resources considered here include oil, gas, coal and nuclear materials. In some cases, an evaluation of energy resources is expanded to include energy-related minerals (e.g. copper, iron) and water supply, but, for the sake of brevity, this is not done here.

2.2.3.1. Classification of resources

One of the earliest problems an energy planner faces in estimating the availability of energy resources is the absence of a universally accepted classification scheme for energy supplies. Definitions vary from country to country and sometimes within a country. The terminology used in resource classification seems intuitively simple, but the actual designation of quantities of energy to be included in each category is less straightforward. Two basic parameters are used to classify resources: the geological certainty of the extent of the resource and the economic feasibility of recovering the resource. The following terms are used by the US Geological Survey [7] and, while they are not universally accepted, their meaning is broadly understood:

– *Resources:* Concentrations of naturally occurring solid, liquid or gaseous material in or on the earth's crust in such form that economic extraction of a commodity is currently or potentially feasible.

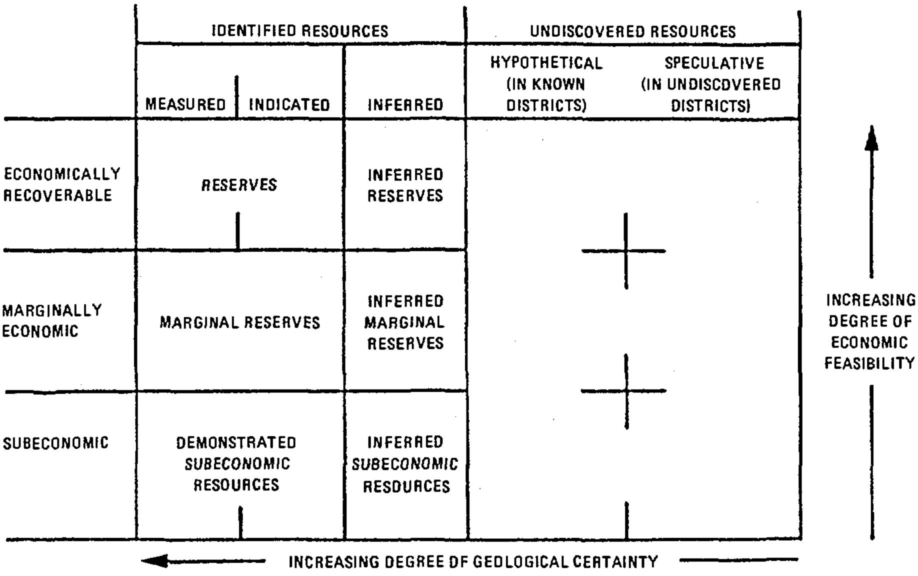


FIG.2.6. Classification of energy resources(from [7]*).*

– *Identified resources:* Resources whose location, grade, quality and quantity are known or estimated from specific geological evidence. Identified resources include economic, marginally economic and subeconomic components. To reflect varying degrees of geological certainty, these economic divisions can be subdivided into measured, indicated and inferred.

– *Undiscovered resources:* Resources the existence of which is only postulated, comprising deposits that are separate from identified resources. Undiscovered resources may be postulated in deposits of such grade and physical location as to render them economic, marginally economic or subeconomic.

– *Reserves:* That part of the resource base which could be economically extracted or produced at the time of determination. The term *reserves* need not signify that extraction facilities are in place and operative. Reserves include only recoverable materials.

– *Measured reserves:* Reserves which can be economically extracted using existing technology and whose amount is estimated from geological evidence supported directly by engineering measurements.

– *Indicated reserves:* Reserves that include additional recoveries from known deposits (in excess of the measured reserves) which engineering knowledge and judgement indicate will be economically available.

– *Inferred reserves:* Reserves in addition to measured and indicated reserves eventually to be added to known fields through extensions and revisions.

Figure 2.6 displays this classification scheme graphically. The terms *proven, probable* and *possible* are also frequently used to classify reserves. These are approximately interchangeable with *measured, indicated* and *inferred,* respectively, but there is no universal agreement on this. The energy planner must determine which classification scheme is in use in his country and must understand the relative geological certainty and economic feasibility of each class.

2.2.3.2. Planning information required

For an energy planning analysis a number of important pieces of information are required. The planner does not need a detailed geological description of energy resources and reserves but must extract the information that is specifically required for the planning study. The basic information includes the following:

- *Total reserves:* The total quantity of an energy supply that is available for extraction and use.
- *Rate of additions to reserves:* The rate at which an exploration programme can be expected to increase the size of the reserves; this is a speculative estimate but is important for long-range planning, especially where extensive exploration activities are under way.
- *Possible production rates:* The maximum rates at which a particular reserve can be exploited; this accounts for physical and practical limitations to how quickly the energy material can be extracted.
- *Extraction costs:* The cost of extracting a unit of energy material; these costs have to be separated into their various components (labour, material, taxes, etc.).
- *Constraints on production:* Any physical (e.g. environmental) or practical (e.g. public policy) constraints on the exploitation of the reserves.

One way to assemble this information into an analytically usable form is to develop a long-run resource supply curve (displayed schematically in Fig. 2.7). The curve relates the production cost (per unit of output) of a single resource (e.g. crude oil) to the total amount of the resource known to be available for production in the future. The supply curve is upward sloping because it is assumed that as the resource is depleted the production costs increase. Other components that may be included in the price of a resource, such as royalties to the resource owner and economic rent, are not included in the supply curve specification; the supply curve represents only the production cost. Each point on the supply curve represents the minimum long-run price that would be acceptable to the resource owner to produce each unit of the resource. This price would allow the resource owner to recover the cost of production but no more.

Resource supply curves are used in energy planning studies to determine the economic competitiveness of each depletable resource relative to other depletable resources, imported fuels and renewable resources. The analysis determines how much of the resource it would be economically competitive to produce in each period, given the resource supply curves that characterize the

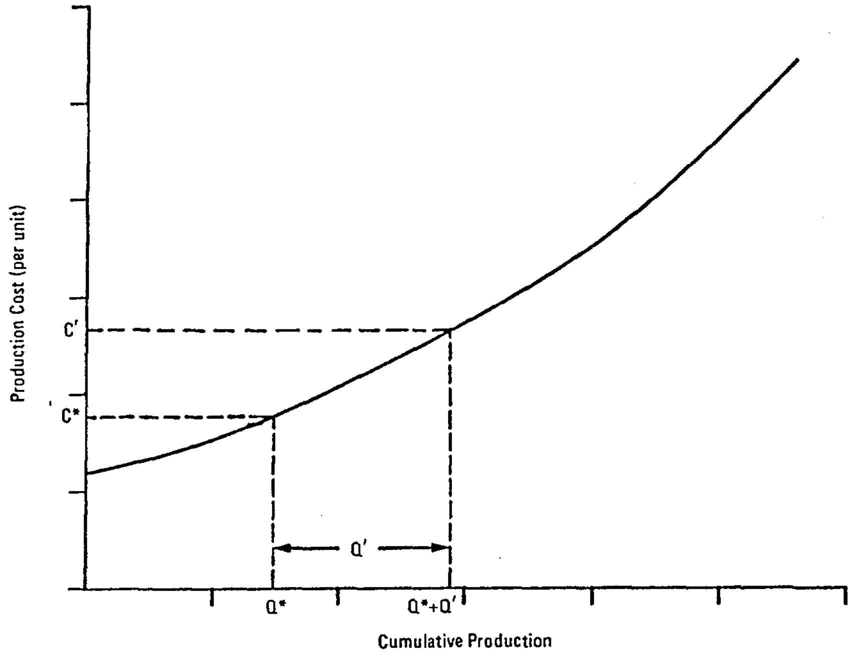


FIG. 2.7. Typical long-term supply curve for depletable resource.

production cost of the resource. For example, referring to Fig. 2.7, if in the first time period Q* units of the resource were produced, the production cost of the marginal unit would be C*. Then C* could be compared with the prices of substitute resources. Similarly, if Q′ units of the resource were produced in the second time period, then the production cost of the marginal unit would be C′. The same reasoning also applies for each period after this. The amount of each resource to be produced in each time period, then, is based on the prices associated with each amount of resource produced in each period. The acceptability of these prices depends in turn on the prices of resources that are substitutes (e.g. other domestic resources, imported fuels and renewable resources).

The production cost for a depletable resource, sometimes termed the *lifting cost,* usually does not reflect the true value or opportunity cost of the resource to the owner and so is not useful by itself in an energy planning study. The opportunity cost of producing a unit of the resource in the current year includes the production cost and a component to account for the fact that production of the resource now eliminates the possibility of producing the resource at some later time when it may have a greater value. This component, termed the *economic rent,* is equal to the difference between the price and the production cost of a unit of the resource. Whether the resource is privately owned or under the control of the government, the intertemporal economic rent in the price of the resource has

TABLE 2.II. SPECIFIC CHARACTERISTICS OF ENERGY RESOURCES

Resource	Categories	Significance to energy planning studies
Crude oil	Chemical class: Paraffinic Aromatic Naphthenic	Determines chemical content of various crude oils and types and mix of products that can be derived from the refining operation.
	Specific gravity (density)	A rough measure of hydrocarbon content. Light crudes (API gravity of 30–50 degrees) generally contain high levels of gasoline and kerosene. Heavy crudes generally contain high levels of asphalt and residuum. Heavy crudes require more extensive refining operations to produce a desirable product mix.
	Sulphur content: Sweet (low sulphur) Sour (high sulphur)	Affects requirements for refining and environmental control.
	Metals content	High heavy-metals content can increase refining costs.
	Location of reservoirs: Onshore Offshore	Offshore reserves are significantly more costly to find and produce.
Unconventional oil	Type of oil source: Oil shale Tar sands	Availability and cost of production must be known in order to determine feasibility.
Natural gas	Relation to oil deposits: Non-associated Associated: Free gas Dissolved gas	Associated gas is often important to the maintenance of oil well pressure and therefore cannot be exploited fully. Non-associated gas is often located far from users and requires larger deposits to make exploitation economically attractive.
	Sulphur content: Sweet (low sulphur) Sour (high sulphur)	Affects requirements for gas processing and environmental control.
Coal	Type of coal: Anthracite Bituminous Subbituminous Lignite Peat	Determines energy content and costs of utilization.

TABLE 2.II (cont.)

Resource	Categories	Significance to energy planning studies
Coal	Physical characteristics: Heat content Ash content Sulphur content Moisture content Coking quality	Determines uses to which coal can be put, energy output potential, environmental and processing requirements.
	Mining method: Underground Strip mine	Determines cost of extraction.
Nuclear materials	Fissile material type: Uranium Thorium	Determines quantity of material available for processing into nuclear fuel.

to be included in the analysis. Higher resource prices embodying economic rent would result in less consumption in the near term and 'save' a pool of the resource for production in the future, i.e. without the rent component the resource would be underpriced. This situation would lead to rapid and total depletion of the resource. The rent component has the effect of extending the production of the resource over a longer time period. Determining the appropriate value of this rent, and hence of the price to be charged for depletable resources, is one of the most important tasks in the energy planning process.

In addition to the basic information on resources and reserves required for an energy planning study (whether or not presented in the form of a long-run supply curve), some very specific information about certain energy resources must be assembled. Table 2.II shows some of the information needed on different fuels and its importance to the planning effort.

2.2.3.3. International energy supplies

As well as data on domestic energy supplies, the energy planner must have some information on the possibilities for imported energy supplies. Imports can be in the form of primary unprocessed energy (crude oil, coal, uranium, etc.) or processed fuel that is ready to use (petroleum products, nuclear fuel rods, etc.). Table 2.III shows some of the ways in which projections of import prices of fuels can be developed.

Crude oil is the most significant imported energy form, and the prices of other energy supplies are often related to it. Given the uncertainty of the crude

TABLE 2.III. INTERNATIONAL ENERGY PRICE PROJECTION PROCEDURES

Energy form	Potential sources and means of delivery	Possible price projection methods
Crude oil	Available from oil-exporting countries. Delivered by tanker or pipeline.	Use scenario approach to determine alternatives.
Petroleum products:	Available from oil-exporting countries and from countries with refining operations. Delivered by tanker or pipeline.	Import price projections can be tied to crude oil price projections.
Light products (e.g. gasoline)		Usually 30–50% higher than crude oil price.
Middle distillates		Usually 10–30% higher than crude oil price.
Residual and heavy products		Usually about equal to crude oil price.
Coal:		
Metallurgical Steam	Available from coal-exporting countries. Shipped by rail or ocean-going coal carriers.	Price usually significantly higher than steam coal. Can be tied to price of crude oil or projected separately. One approach is to tie the price to the electricity generation equivalent of residual fuel oil.
Natural gas	Available from gas-exporting countries. Delivered by pipeline or in the form of liquefied natural gas.	Usually priced higher than crude oil. One method is to tie the price to the energy content equivalent of oil.
Uranium	Available from countries exporting uranium or nuclear fuel.	Price based on processing technique used (e.g. amount of enrichment). Growth in prices generally not tied to crude oil prices.

oil markets, the most frequently used approach is to develop a set of scenarios of the future oil price. The energy planning analysis is then carried out for each scenario in order to determine the sensitivity of the results to changes in the import price. Growth rates in crude oil prices of 0–5% per year (in constant currency) have been used for energy planning studies. The choice is based on the best estimate of the analyst.

Petroleum product import prices are usually tied to crude oil prices. The lighter products, such as gasoline, are often taken to be considerably more costly than crude oil, while the residual products may be priced at or below crude oil.

The growth in coal prices is highly speculative and will depend on whether steam coal becomes a major international energy commodity. One method of developing an upper limit to steam coal prices is to assume that potential purchasers will not pay any more to generate electricity by using coal than by using residual fuel oil. This ties the coal price to the residual fuel oil price. Metallurgical coal must be priced separately from steam coal because of its specialized uses; it is significantly more costly.

Natural gas, in the form of either gas or liquefied natural gas, is usually more expensive than oil because it is a premium fuel. Nevertheless, its price is often related to crude oil prices. There have been some attempts to tie the gas price to the energy content equivalent of oil.

Nuclear fuel, traded in a variety of forms including U_3O_8 yellowcake, enriched uranium, and fabricated reactor fuel rods, is not as sensitive to oil prices as other energy forms. The price of U_3O_8 showed a relatively steep rise following the 1973–1974 crude oil price rises but actually dropped after the 1979 oil price rise [8]. Enrichment service charges showed a steady increase between 1970 and 1980, with no discernible tie to oil price increases. For these reasons, projections of nuclear fuel prices are not usually tied directly to crude oil price projections. Growth in nuclear fuel prices has generally been considered slower than crude oil prices.

Whatever method is chosen to project international energy prices, the safest procedure for the energy analyst is to construct several alternative price scenarios and try them all. This will help determine whether the resulting energy supply system is very sensitive or insensitive to the import fuel price.

2.2.4. Energy supply technologies

One final piece, the energy technology evaluation, is needed to complete the database development as shown in Fig. 2.1. Many energy technologies are available, each with its own characteristics and applications. Information is required about each technology that is considered a potential candidate for some role in the energy supply system. This information must be assembled consistently so that the alternatives can be compared. Note that the purpose of this step in the energy planning process is to assemble information about energy technologies; the actual comparison of alternatives and selection of particular technologies is made as part of the integrated analysis and later steps.

For convenience, the technology evaluation can be divided into three basic categories: fossil fuel technologies, renewable resource technologies, and electric system technologies. This distinction is based on the usual separation of engineering expertise. Each category has a unique set of characteristics and is evaluated in a special way. Before discussing how each is treated in its own way, it is important to identify the common aspects of each technology system for which data must be assembled. Table 2.IV gives the information required for each technology.

Engineering performance data describe the type and quantity of energy that can be delivered by the supply technology and the efficiency with which it delivers the energy. This information is used to determine the size and extent of the energy supply system needed to meet demand. Note that estimates of the performance of technologies not yet in place in the country must be included in order to evaluate their potential for application.

Economic data are used to estimate the costs of the various technologies. Cost is one of the most important factors in the choice of energy supply systems. Cost analyses are performed in numerous ways, that most frequently used being a discounted present value analysis. Whatever the method, sufficient cost and financial analysis data must be included for each technology to be studied.

Ancillary data account for other parameters of an energy supply technology, besides engineering performance and cost, that may be significant in deciding whether or not to implement the technology. The data listed in Table 2.IV show the most frequently considered parameters; others can be added as necessary.

It is important to compile the data on the various energy supply technologies consistently, particularly the definitions of terms and the values used, since all of the technologies will be compared on the basis of these data. For example, if the capital cost data are to include interest during construction, then this must be included in the capital cost of all the systems. Thermodynamic efficiency has a different implication for a coal-fired power plant than for a solar water heater. The terms must be carefully evaluated and consistently applied for the analyses concerned. Several sources have attempted to compile data on energy supply technologies in such a consistent way [5, 9, 10].

2.2.4.1. Fossil fuel energy technologies

Energy technologies using oil, gas and coal are the basis of most commercial energy supply systems. The systems that extract, process, transport and deliver fossil fuels are characterized by large centralized facilities (e.g. refineries, pipelines, coal mines). In the context of energy planning, this centralized character of fossil fuel systems means that the supply technologies can be evaluated by considering large projects and determining the viability of these projects by means of traditional engineering and economic analysis procedures.

Table 2.V shows some of the stages in the fossil fuel cycle that can be considered as candidates for the fossil fuel system. Obviously, the use of fossil fuels involves many different stages and each stage has a variety of alternative approaches. In analysing one particular fossil energy supply system, all the steps necessary to deliver the fuel to end-users must be considered. For example, if a country is considering replacing imported oil by imported coal, then all the steps of the coal

TABLE 2.IV. TYPICAL ENERGY SUPPLY TECHNOLOGY DATA REQUIREMENTS

Parameter	Examples
Engineering performance data:	
Energy output	Type of products output Range of output
Energy input	Input materials Restrictions on inputs
Thermodynamic efficiency	Current and future improvements
Performance limits	Capacity design, maximum, minimum Operational limitations Reliability
Technology status	Commercially available Research Pilot plant
Economic data:	
Capital cost	Labour, materials Interest during construction Foreign and domestic component Per-unit of output Current, future
Non-fuel operating cost	Labour, materials Taxes Per-unit of output
Output energy cost	Including capital charges, fuel costs, non-fuel operating costs Taxes Per-unit of output
Financial data	Interest rates[a] Return on investment[a] Discount rate[a] Foreign exchange implications
Ancillary data:	
Environmental burdens	Air pollution Water pollution Solid waste Noise
Labour requirements for construction and operation	Quantity Skilled, unskilled Foreign, domestic
Barriers to implementation	Social acceptance Policy issues

[a] *Generally not technology-specific.*

TABLE 2.V. TYPICAL STAGES OF THE FOSSIL FUEL CYCLE

Resource	Extraction	Processing	Transport	Conversion
Oil	On shore	Refining	Tanker	Combustion
	Off shore	Well-head processing	Pipeline	Feedstock
	Secondary recovery		Rail	Lubricants
Gas	On shore	Well-head processing	Pipeline	Combustion
	Off shore	Liquefaction	Rail	Feedstock
	Associated		Ship	
	Non-associated			
Coal	Underground	Cleaning	Rail	Combustion
	Surface	Solvent refining	Barge	Coke
	In situ combustion	Gasification	Slurry pipeline	
		Liquefaction	Truck	
Oil shale	Mining	Retorting	Tanker	Combustion
	In situ combustion	Shale refining	Pipeline	Feedstock
			Rail	Lubricants
			Barge	
Tar sands	Mining	Retorting	Tanker	Combustion
	In situ combustion	Refining	Pipeline	Feedstock
			Rail	Lubricants
			Barge	

fuel cycle (processing, transport facilities, environmental control, etc.) must be considered. It is not enough to base a decision simply on fuel cost comparisons.

In many regards, fossil fuels are interchangeable; furnaces and boilers have been designed to burn oil, gas or coal. For planning purposes, fossil fuels offer the largest range of fuel substitution potential and thus offer the planner the widest range of options. There are, however, a number of situations where it is not possible to substitute one fossil fuel for another. For example, certain industries require clean fuels, such as gas, to avoid product contamination. These restrictions apart, fossil fuels are often competitors in the energy market.

TABLE 2.VI. METHODS OF ESTIMATING RENEWABLE RESOURCES

Resource	Major parameters defining resource	Method of estimating resource base for planning
Solar:		
Thermal Photovoltaic	Incident solar radiation	Estimate either quantity of heat provided or amount of electricity generated. In both cases some assumptions regarding technology performance have to be made.
Wind capacity	Average wind velocity	Estimate potential electrical generating capacity. Assumptions must be made regarding wind turbine technology.
Biomass:		
Wood Special crops Industrial waste Agricultural waste Urban waste	Quantity of material produced Heat-content of material	Estimate heat equivalent of using crops. Efficiency of conversion technology, e.g. biogas plants, may be estimated.
Ocean systems:		
Tidal Wave Ocean thermal energy conversion (OTEC)	Height difference in tides Wave height and frequency Water temperature difference	Estimate potential electrical generating capacity of each system. Assumptions must be made regarding performance of each technology.
Small-scale hydroelectric	Hydraulic head Flow rates	Estimate potential electrical generating capacity. Assumptions must be made regarding technology and number of sites available.
Geothermal	Temperature Fluid flow rate	Estimate either electrical generating capacity or quantity of heat provided. In both cases performance of the technology must be estimated.

2.2.4.2. Renewable resource technologies

Renewable resource technologies comprise systems where the basic energy input is derived from a source that is renewed periodically. Table 2.VI lists the available renewable resource technologies. (The most widely used renewable resource, large-scale hydroelectric power, is not included here but is reserved for consideration with the electric sector technologies.)

Renewable resources are an important part of the energy supply available to a country and must therefore be considered as part of the resource base. However, these resources cannot be characterized in the same way as fossil fuels. The definitions of the different types of 'reserves' as described in Section 2.2.1 do not make sense for renewables. In some cases, for example solar and wind, the concept of a reserve base has no real meaning. Each renewable resource must be treated somewhat differently and characterized separately for planning purposes. Table 2.VI shows the major parameters used to characterize the various renewable resources and how the resource base is estimated for planning purposes. Note that in almost all cases it is necessary to make some assumptions about the performance of the technology used to extract usable energy in order to arrive at an estimate of the resource base. This is quite different from the process used for fossil fuels.

In some cases it is also necessary to make some assumptions on the economic feasibility of the technology in order to arrive at an adequate resource base estimate. This is because much of the renewable resource base cannot be economically recovered. Consider direct solar energy, for example. The total quantity of incident solar radiation is very large; it is not reasonable to include this total as part of a country's energy resource base for planning purposes. A first step is to estimate the quantity of solar energy that can be recovered with available or advanced technology (photovoltaic systems, for example, have efficiencies between 2% and 7%). This quantity is still too large for planning purposes since it assumes that the entire area of a country would be covered with solar collectors. A second step is to make some assumptions on the extent to which the technology might be deployed. This would give a limit to the viability of using the resource.

Another factor complicating the analysis of renewable resources is that many systems are not large centralized facilities that can be analysed by traditional project analysis techniques. Rather, there are many small decentralized systems (solar water heaters, small wind electric generators, biogas plants, minihydro plants, etc.) which must be analysed in a different manner. One way of looking at them is from the user's point of view. In this perspective there is a competition in the marketplace between these systems and conventional fossil fuel supplies. The user chooses the renewable system or the conventional system on the basis of his perception of the delivered cost of energy (including investment cost, fuel cost, operating costs, reliability, convenience, etc.). As an example, a home-owner will install a solar hot water heater when he perceives that the cost of hot water would be lower with this system than with an oil- or gas-fired unit. This type of evaluation of renewable resource technologies is therefore based on a market penetration analysis rather than the project analysis of conventional fossil fuel facilities.

One interesting point about this type of evaluation is that the use of renewable resource technology can lead to a 'backward bending resource cost curve' as opposed to the conventional monotonically increasing resource cost curves described in Section 2.2.3. Two examples illustrate the point. First, an increased use of solar water heaters and an increase in market penetration will result in a decrease in unit capital costs owing to the efficiencies in volume manufacturing. This cost decrease translates into reduced hot water supply costs. Second, increased market penetration of fossil fuel based water heaters will marginally reduce unit capital costs on the one hand but will significantly increase fossil fuel demand on the other, thereby driving up the fuel cost component. The net effect will be an overall increase in hot water supply costs.

The complicating factors of definition of the resource base and treatment of decentralized technologies make renewable resources somewhat difficult to treat in an energy planning analysis. Nevertheless, if consistently defined, the data prescribed in Table 2.IV will be as useful for the renewables analysis as for the conventional fuel analysis.

2.2.4.3. Electric system technologies

The technologies available for generating electricity vary from commercially available systems to advanced concepts and from large centralized facilities to small decentralized equipment. Table 2.VII shows the types of systems. Transmission and distribution facilities must be considered in addition to generation equipment. Assembling data for electric generator systems is relatively straightforward. The biggest problem encountered is getting agreement on certain data items, particularly costs. In a sense, there is almost too much information since there are numerous equipment manufacturers with different ideas on costs, performance, etc. The energy planner is often obliged to sort out the information and choose the appropriate data.

Self-generation systems complicate the assembly of electrical system information, particularly in developing countries. These systems are the smaller generator units located at an industrial or other facility and are tied to that facility's needs. They may or may not be connected to a national or regional grid, and they may or may not provide electricity to the grid when it is not in demand locally. Countries with weak electrical grid systems usually have more self-generators as industries try to ensure a reliable source of energy. In some countries these self-generators are a major component of the electrical system, and information must therefore be assembled for them.

Another complicating factor in electrical system analysis is the use of cogeneration equipment. These are like self-generation equipment in that they are decentralized and located at individual industrial or other facilities. However, they are used to provide both electricity and process heat or steam rather than to supplant a weak grid system. In assembling performance data on these systems, both the electrical and heat outputs of the equipment must be considered, and this significantly changes the cost and efficiency aspects of the systems. The use

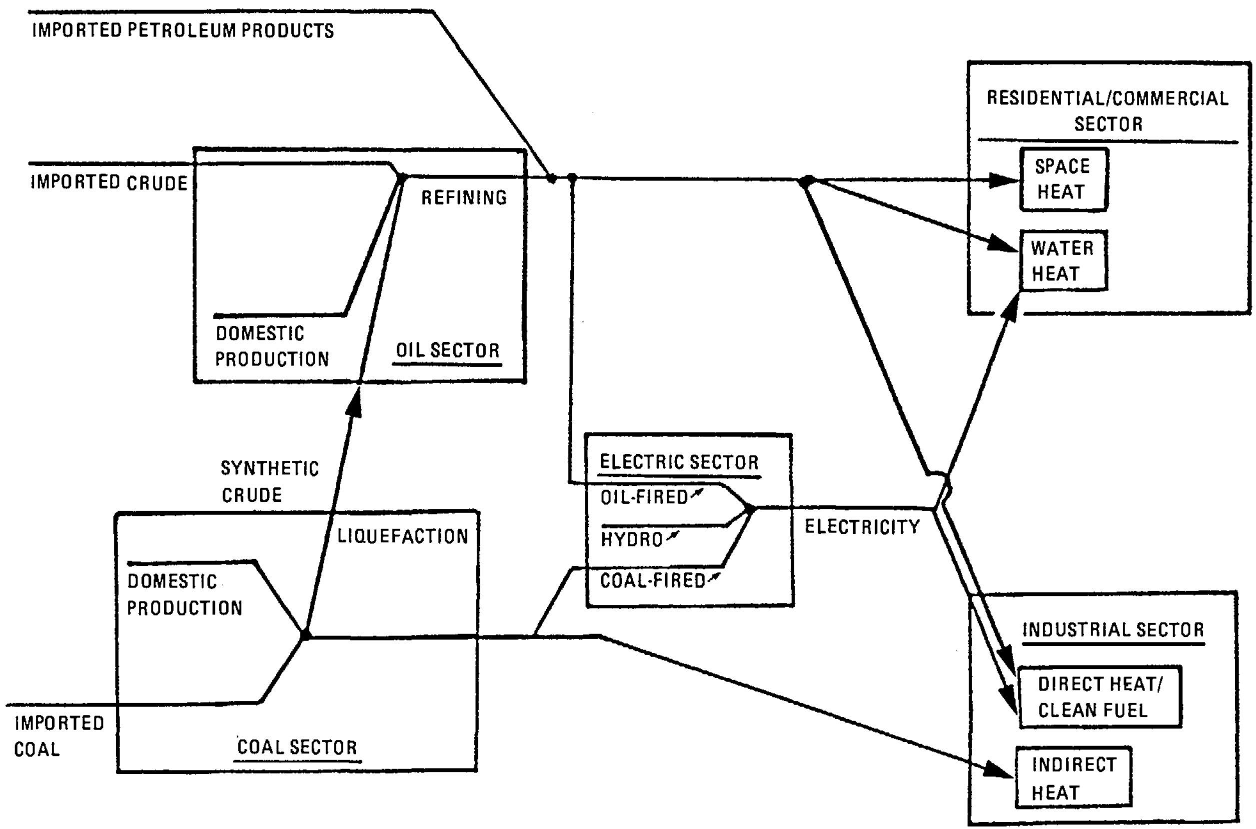


FIG. 2.8. Simplified supply/demand structure.

TABLE 2.VII. TYPICAL ELECTRIC PLANT TYPES

Generator system	Fuel
Boiler-steam turbine	Oil Coal Gas Nuclear Wood Urban waste Biomass
Gas turbine	Distillate oil Gas
Diesel generator	Diesel fuel
Renewable resource systems:	
Hydraulic turbine	Water: storage dam Water: run-of-river
Others	Photovoltaic Solar thermal Wind Ocean thermal energy conversion (OTEC) Wave power Tidal power Geothermal

of cogeneration equipment may increase with increasing concern for the most efficient use of energy.

More details on electric system information are given later in this guidebook.

2.2.5. Integrated energy analysis

Figure 2.1 shows that after completion of the database, an integrated analysis is performed to structure the data in a consistent format for evaluation of alternatives. The two major components of the integrated analysis are the *supply/demand balance* and the *impact evaluation.* Some of the integrated analysis steps can be carried out while the database development is still under way; others must have a completed database before they are initiated.

2.2.5.1. Developing a supply/demand network

The first step of the integrated analysis is to develop a supply/demand network that traces the flow of energy from primary resource through to end-use. Figure 2.8

is a graphic description of a typical network; it is a greatly simplified version for illustration only. The same type of structure can also be displayed in tabular form. A number of standardized tabular displays have been developed by the United Nations, the Organisation for Economic Co-operation and Development (OECD) and the Latin American Organization for Energy Development (OLADE), among others. The details of the structure are constrained by a number of factors including:

– The types of questions that have to be answered in the energy planning process,
– The availability of information and data,
– The analytical tools that will be used.

To develop the structure on the demand side, the energy-using sectors must be broken down into elements with common characteristics. These sectors must be further disaggregated into subsectors to provide more detail for planning. The subsectors must then be disaggregated by end-use device classifications to provide the most detailed perspective of the energy use pattern. On the supply side, all possible pathways from primary resources to end-users must be identified. Potential new steps in a fuel cycle as well as existing steps must be identified. Note that the process of creating these classifications for national energy planning must necessarily vary from country to country to reflect different energy use patterns, energy consuming devices, and energy supply systems.

2.2.5.2. Developing a base year balance

When the network is formulated, the next step is to develop a base year energy supply/demand balance. This requires filling in the network structure with the quantity of energy flowing along each link. Account must be taken of efficiencies and losses at each step in the network so that there is a mathematically consistent balance from one end to the other.

The base year balance is the foundation on which the projections for future energy system growth will be built. It must therefore be developed consistently with the structure used for economic growth projections. The data for the base year balance should be compiled as part of the database development tasks. One of the key efforts that will be required is to resolve the inconsistencies in data that inevitably appear. For example, data on the production of petroleum products obtained from refinery operators will not match data on sales to consumers. Differences result from losses unaccounted for, different accounting procedures, errors in data tabulation, etc. The effort required to resolve these differences should not be underestimated.

The selection of the base year to be used is an important consideration. The base year should be as close to the current year as possible so as to reflect more accurately the existing energy situation. A number of issues may preclude the choice of a very recent year; the most important is the availability of data.

In all countries there is a time lag in the compilation of a complete set of energy supply and demand information. This delay can be one year, two to three years, or even as long as four to five years. In any case, the completeness of the data set is the biggest determining factor in the choice of a base year.

Another issue affecting the choice is the representativeness of the base year data. Although it is difficult, if not impossible, to find a year that is 'normal' in all aspects of a country's energy situation, the planner should try to avoid choosing a base year that is clearly anomalous in terms of energy conditions. Examples of such situations would be a year of unusually severe weather resulting in droughts (and decreased hydroelectric output), a year of economic turmoil with major disruptions to economic and energy-consuming activities, a year with major natural catastrophes (floods, earthquakes, etc.). Such conditions should be avoided where possible as they could give an unrealistic picture of energy development. It is more desirable to use an earlier and perhaps more representative year than one which does not reflect a reasonable trend.

Although the principal function of the base year balance is to display the flow of energy, another important piece of information that must be shown on the base year network is the price of the various energy commodities. On each link of the network, prices must be displayed which reflect the cost of energy at that stage in the network. This will allow an economic comparison of energy alternatives in the base year and will provide the starting point for the analysis of future possibilities. The specification of the prices should be broken down into the components: production cost, taxes, royalties, subsidies, etc., which will allow the planner to investigate the effects of alternative pricing policies.

2.2.5.3. Constructing projected supply/demand balances

The development of supply/demand balances for future years is a key component of energy planning analyses. These projected balances define the size and configuration of the energy supply system in the future. There is a wide variety of analytical approaches to constructing these balances and a number of methodologies and models are available to assist the planner. The choice of the appropriate analytical approach and the model(s) should be the subject of an intensive review by the planner. There are numerous documents [11–14] which give details of the availability of various models, comparing the performance and accuracy and judging the theoretical structure of each model. No one system or model can be considered appropriate for every application. The planner must decide on the appropriateness of assumptions on which the model is based, the kind of information provided by the model, the data requirements of the model, the effort required to get the model operational, the experience level of the analytical staff in using and interpreting the results of a model correctly, among many other factors. Only after these have been taken into account should a choice be made. No attempt is made here to provide a comprehensive review of energy models and their application; only the major differences in approach are outlined.

The two fundamental approaches to projecting future supply/demand balances are the *prospective* and the *normative* approaches. The prospective approach relies on analysis of past trends and behaviour and on an estimate of how energy users and suppliers will respond to different conditions. This information is then used to predict the future demand for energy and how it will be supplied. In contrast, the normative approach postulates a scenario about future conditions; it attempts to design an energy supply system that will meet certain objectives (e.g. least cost, lowest foreign exchange requirement). The difference between the two methods is that the prospective approach attempts to predict developments. Since it relies on the extension of historical behaviour into the future, it is most useful for short- and medium-term analyses. The normative approach takes the view that the future is so uncertain that the only way to deal with it is to determine a range of possible scenarios which are likely to occur and to evaluate what type of energy supply system might be necessary to meet the needs. This approach has been widely used in medium- and long-range analyses where historical trends are not as influential in determining future patterns. Energy models used for constructing future supply/demand balances can be prospective, normative or a combination of the two. It is important for the planner to understand which method is being employed and to interpret the results accordingly.

It is often beneficial for a planning group, before selecting a complex model, to go through the process of constructing future supply/demand balances manually, i.e. the supply/demand network can be filled in for future years of interest by using the considered judgement of the planners. The planner can decide how much fuel will be demanded by each sector, what supply system configuration will be used, and the effects of various policy considerations. Although this procedure lacks the aura of sophistication surrounding the use of computerized models, it provides an enormous amount of insight into the key problem areas. For example, it can define where the key choices in energy alternatives are; it can identify which decisions will have significant consequences for the energy supply system and which will have only minor effects. If an integrated energy supply/demand analysis has never been made before, the manual balance approach should be implemented as a first step to help determine what issues need to be tackled with more sophisticated tools.

An analytical procedure for constructing a supply/demand balance for the electric sector is described later in this guidebook. The WASP model is one approach to developing a least-cost electricity supply system. It is easy to extrapolate the concepts used in the WASP model to the entire energy supply system.

2.2.5.4. *Selecting and evaluating alternatives*

Whatever analytical methodology is employed to construct future supply/demand balances, the usefulness of the approach to planning efforts is apparent when alternative conditions are evaluated. This is where the planner can gain

TABLE 2.VIII. TYPICAL ALTERNATIVES FOR EVALUATION

Energy issue	Specific alternatives
Economic growth	Rate of growth Structure of economic growth
International energy prices	Price of crude oil Price of petroleum products Price of coal Price of gas Price of nuclear fuel
Domestic energy price policy	Subsidies Taxes Price controls
Conservation programme	Business-as-usual conservation efforts Moderate conservation programme Aggressive conservation programme
Renewable resource programme	No special emphasis Incentive programmes
Supply system configuration	Least-cost system Restrictions on certain imports Requirement for diversification Emphasis on indigenous supplies Choice of specific technologies

insight into the potential effects of different strategies and policies on the development of the energy sector. It is easy to develop a list of possible alternatives the planner would like to consider. Table 2.VIII shows some of the typical alternatives that might be evaluated using the integrated analysis methodology. Each specific alternative can be considered as a case to be studied by means of the methodology. It is also possible to combine the various alternatives into sets. For example, one case might be based on a high growth rate, moderate rate of oil price increase, aggressive conservation efforts and a requirement for a diversified energy supply system. The planner can then construct the supply/demand balance for this set of conditions and evaluate the impacts of the balance.

It is easy to see that the number of possible alternatives for consideration can become very large owing to the combination of conditions. The planner must be selective in deciding the number of alternatives to be considered. Certain configurations will lead to little or no change and do not provide any useful information on which to base a decision. Others are known, a priori, not to be feasible and should be discarded. With a systematic methodology that can produce supply/demand balances accurately and rapidly, it is often tempting to evaluate every possible combination of conditions. Planning can then deteriorate into a numerical exercise in which a large volume of data is generated but not evaluated in any detail. The planner must exercise careful control over this process.

In dealing with electric system analysis, the problem of selecting alternatives to evaluate is compounded. For each set of conditions in the economy and in the overall energy system there is a wide range of possible ways to build the electric system so as to satisfy the requirements. The electric system planner must work closely with the energy planner to screen out impractical or unfeasible alternatives and avoid wasted effort.

2.2.5.5. Evaluating the impact of a supply/demand balance

Once a supply/demand balance has been constructed, the impacts or implications of that balance must be determined. The evaluation of these impacts provides the basis for developing information for decision-makers. Section 2.1.3 gives some general guidance on what information needs to be generated by the planning process. Table 2.IX specifies in greater detail how the impacts evaluated as part of the analytical process match the decision-making requirements. Additional impacts can be included for issues of particular concern to the country.

Some of the impacts require a fairly detailed computating procedure. For example, the computation of the costs of constructing new energy facilities requires an estimate of total capital costs, interest during construction, escalation factors, contingencies, and a time distribution of cash flow. For completeness, the calculation should be expressed in constant currency, current value currency, and be discounted to present value. A number of analytical tools are available to the planner to help compute some of the impact parameters. The tools are generally straightforward computational algorithms but they should be evaluated for compatibility with the rest of the analytical methodologies being used.

2.2.5.6. Choosing among alternatives

The final step of the integrated analysis is to choose from among the alternatives and to select from the impacts evaluated the information that will be presented to decision-makers for review. In Section 2.1.5 emphasis was placed on the need for the analyst to prepare the results in a form suitable for use by decision-makers. Such preparation involves the collection of all the information generated as part of the integrated analysis and the assembly of this information into a format suitable for review and evaluation by a decision-maker.

The decision-making process can be expected to lead to additional analyses and to changes in the original set of assumptions. If the analytical methodology is properly set up, such iterations should be possible with a minimum of impact and extra effort.

TABLE 2.IX. TYPICAL IMPACTS TO BE EVALUATED

Decision-making information	Specific impacts to be evaluated
Energy requirements	Total quantity of energy required Quantities of each type of energy (fuel, electricity) required
Energy supplies	Sources of energy available Imports required Indigenous resources used
Supply system configuration	Number and type of energy facilities required (e.g. power plants, refineries, pipelines) Dates when new facilities must be operational to meet demand
Costs	*Capital investment required in energy facilities* Operating costs of new and existing equipment Delivered costs of fuel and electricity
Financial data	Foreign exchange required for energy system Financial analysis of energy projects Revenue generated from energy system
Economic effects	Energy sector contribution to GDP Energy sector requirements as a portion of GDP
Labour	Personnel required for construction of energy facilities Personnel required for operation and maintenance of energy system Skilled labour requirements
Environmental effects	Air pollution Water pollution Solid waste Noise Hazardous waste
Materials	Material requirements for the energy sector Imported material requirements

2.2.6. Role of electric system planning

The context of the preceding discussions on analytical methods has been overall energy planning. Obviously, the electric system analysis is a key element of this process. The methods and analytical tools used by electric system planners follow the same general steps as those used by overall energy planners. The only distinction is in the level of detail.

The need for thorough integration of electric system planning efforts into an overall energy planning exercise must be emphasized. Often the electric system planning is performed separately from other planning efforts, the only point of contact being a load forecast that may be tied to the economic growth plan. At the same time, the overall planning studies often overlook the work done by the electric system planner and so develop electricity analyses with little or no consideration of the efforts already expended. It is vitally important to avoid this lack of interaction. From an analytical standpoint there is no reason why detailed electric system planning and overall energy system planning cannot be conducted in a consistent and mutually beneficial fashion. The organizational requirements for implementing this are often the only obstacles.

2.3. ENERGY PLANNING CASE STUDIES

This section describes previous energy planning studies, how they were carried out, the results of the analyses, and what could be improved upon. This is not done by describing results in detail, but rather by analysing the planning process involved in each study.

2.3.1. Studies for energy and nuclear power planning in IAEA Member States

As discussed in Section 1.1, the IAEA conducts an extensive programme of work in the field of nuclear power planning and implementation. One of the most important activities in this programme is the execution of energy and nuclear power planning (ENPP) studies in co-operation with requesting Member States. As an example of an ENPP study, this section describes the study carried out in co-operation with the Government of Algeria during the period 1980–1982 [15].

2.3.1.1. Energy and Nuclear Power Planning Study for Algeria

In response to a request from the Algerian Government, the first IAEA mission to Algeria took place in 1980. It consisted of three experts who stayed in the country for two weeks to investigate the possibilities of undertaking a study on the role of nuclear energy in supplying part of the electricity that Algeria will require in the next decades.

As a result of this first mission it was agreed that such a study should be carried out by a joint team consisting of two experts from the IAEA and five Algerian experts. The Algerian subteam were all staff of the Société nationale d'électricité et du gaz (SONELGAZ), the company which was assigned full responsibility for the study by the Algerian authorities. Close co-operation was maintained between both subteams, and several missions by IAEA experts to Algeria and SONELGAZ experts to Vienna were undertaken during the execution of the study.

Taking the Agency's first mission as the starting date, the study took two years, during which time the total manpower requirement reached 6–8 man-years. This figure does not take into account the contribution from many staff members of several Algerian organizations who supplied useful information and data for the study; nor does it include the development of the computer codes carried out in Vienna by the IAEA.

At the outset of the study, it was recognized that the role of nuclear power in the electricity supply of a developing country, such as Algeria, could not be effectively studied in an isolated manner; it must be examined in the context of the overall energy requirements of the country consistent with the goals for national economic, social and technological development. This made it necessary to examine the energy demand in all its forms before undertaking an assessment of the role of nuclear energy in Algeria. In view of the relatively long lead times required for implementation of a nuclear power programme, it was deemed necessary to consider the long-term period of about 30 years.

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 might allow the Algerian energy authorities to gain a better idea of the impact and the social and economic repercussions of some decisions and thus improve the decision-making process on energy matters.

2.3.1.2. Purposes and scope of the Algerian Study

The main purpose of the study was to initiate ideas on the role that nuclear energy could play in meeting the energy requirements of Algeria. Two successive analyses were performed.

The first analysis consisted in evaluating the final energy requirements which will result in the medium and long term (by the year 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, 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. When 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 might 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. At a later stage, other scenarios could be constructed for the purposes of more sensitive analyses, but it now seems certain that these three basic scenarios largely cover the spectrum of possibilities. This study was conducted by means of the MAED model (MAED-1 version, see Appendix A).

The second study is concerned only with the results regarding future electricity requirements, which are used as input data to study the optimization of Algeria's future electricity generating system. Various methods of generation (e.g. gas- or oil-fired, hydroelectric and nuclear power plants) were analysed and included in an econometric model in order to determine sequentially the most economic pattern of expansion for the power generating system. 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 foregoing 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. This analysis was performed by means of the WASP model (WASP-III version, see Chapter 11).

An additional objective of the study was to enhance the country's capabilities of 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.

2.3.1.3. Conduct of the Algerian Study

There was a division of responsibilities between the IAEA team and the national team in carrying out the various tasks in the study. The national team was responsible for gathering and analysing the information to be used, preparing scenarios of development, analysing the results, and preparing the draft report. The IAEA team was responsible for providing assistance and guidance in the conduct of the study and execution of the computer runs needed, training their Algerian counterparts in the use of the computer models, and implementing these models on the Algerian computer facilities.

Gathering input information is a vitally important part of an ENPP study; in Algeria it was facilitated by the fact that sufficient statistical data on energy production and consumption were available. However, a great effort was demanded of the national team, working in co-operation with experts from the Algerian organizations concerned, to ensure that this information was consistent.

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

Preparation of the scenarios of development was a very important phase of the study and required:

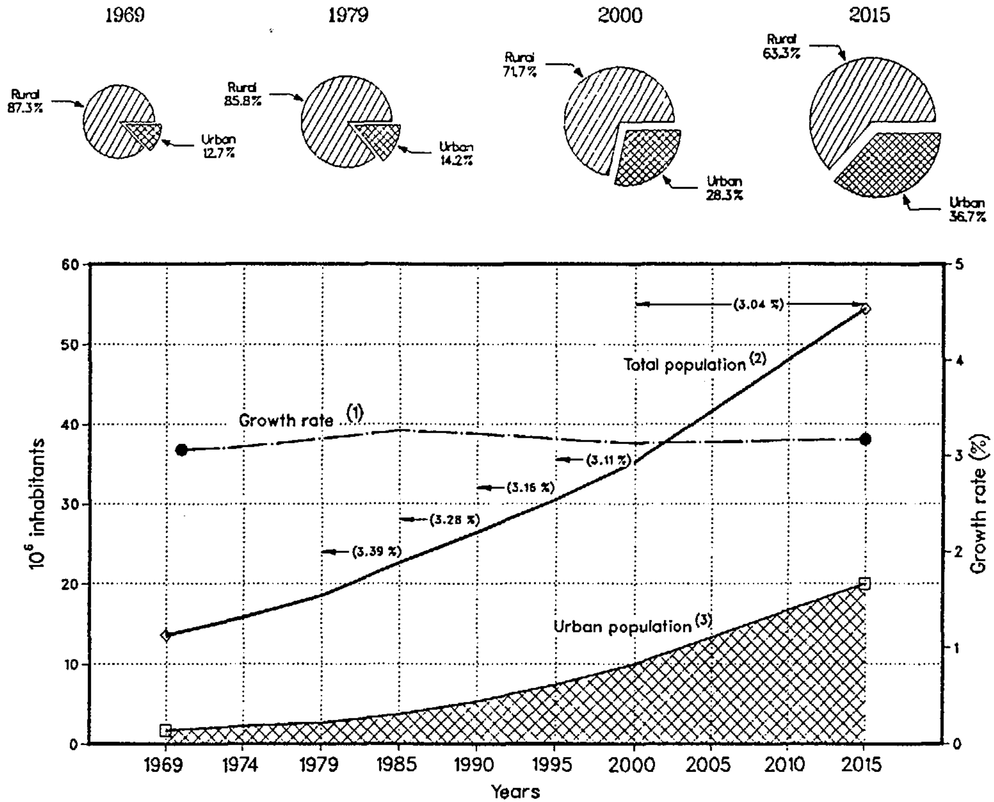
- Definition of a consistent socio-economic framework. This, for a developing country, amounts to selecting a form of development, i.e. to defining options and priorities and predicting structural changes in the economy while ensuring overall consistency.
- Identification of the factors determining energy consumption, and particularly electricity consumption. This 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 the available information, an iterative approach was adopted for the study alternating between MAED runs, additional analysis and gathering of data and meetings with the Algerian experts concerned.

Given the purpose of the study, the variables selected to differentiate one scenario from another correspond to those parameters with a direct or indirect influence on the demand for electrical energy. The scenarios chosen were therefore based on 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 dwelling, population mobility and vehicle consumption; and (b) assigning to 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 for 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 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 a view to determining a single consistent socio-economic framework for the three scenarios.

2.3.1.3.1. Features common to 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 (Fig.2.9).



(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.

FIG.2.9. Energy and nuclear power planning study for Algeria: past and future trends in total and urban population and average annual growth rate.

- *In economic terms.* GDP growing over the study period but at slightly decreasing rates over the study period (Fig.2.10).
- *In social terms.* Major housing programmes aimed, in a first step, at 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 levels comparable to those 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. Recourse on small scale to solar energy for low temperature heat applications in households and services sectors; a common hypothesis for all three scenarios which was constructed only to show how the model can be used in this field, since additional studies will be needed in order to study the role of solar energy in meeting future energy requirements of the country.

2.3.1.3.2. Qualitative description of three scenarios

The scenarios selected were ranked as low, medium and high according to the level of electricity consumption. The variables related to electricity demand and to 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 which compose each scenario are:

- Specific electricity consumption per unit value added of the various sectors;
- Use of electricity in industrial heat applications, especially in steel-making;
- Railway electrification;
- Specific consumption level (kW·h/m^2 per year) in services sector;
- Specific consumption level (kW·h/dwelling per year) in the domestic sector;
- Use of electricity for heat applications in domestic and services sectors;
- Use of solar energy in manufacturing industries (which for reasons of consistency was higher when the market penetration of electricity was relatively low).

2.3.1.3.3. Optimization of investments in the electricity sector

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

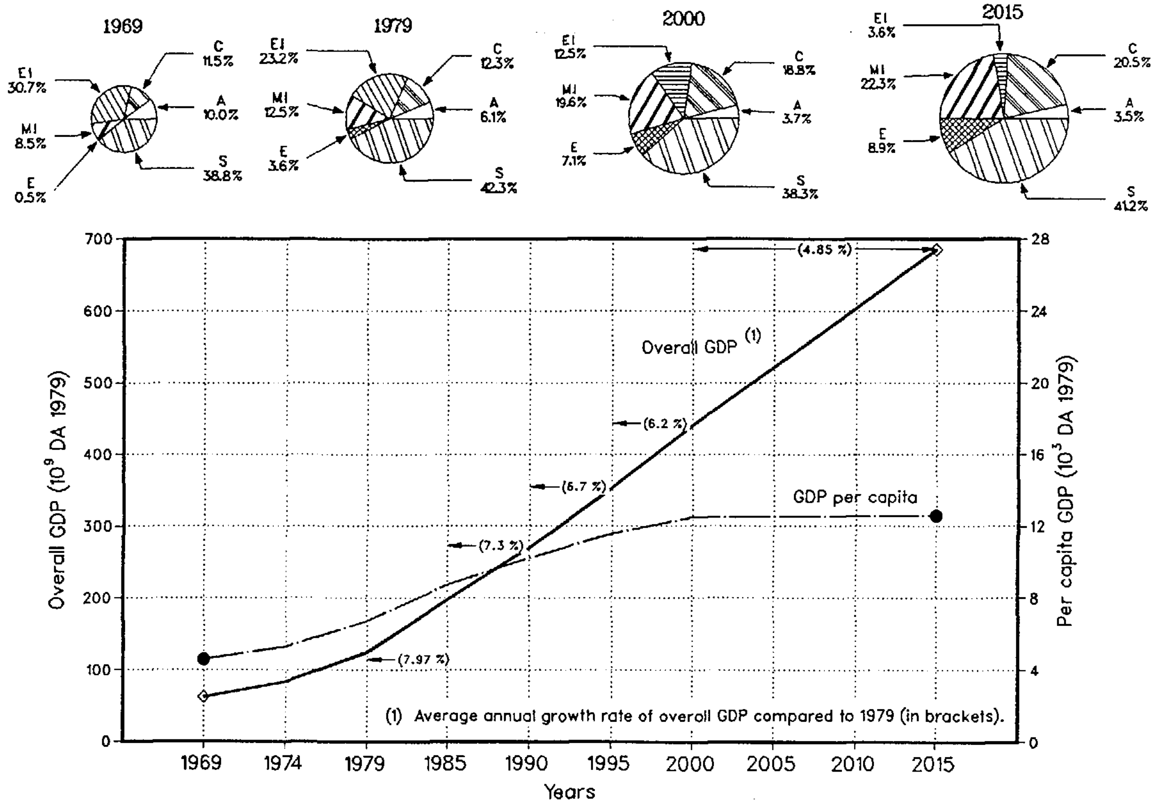


FIG.2.10. Energy and nuclear power planning study for Algeria: past and future trends in overall and per capita GDP and distribution by sector (in Algerian dinars (DA)). A: Agriculture. MI: Manufacturing industries. C: Construction. E: Energy. EI: Extractive industries. S: Services (including transport).

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

- The composition of the '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 of future developments and local conditions;
- Fuel prices, set on the basis of international prices but also reflecting the market conditions for export of natural gas from Algeria;
- Constraints to the expansion problem, which were set with due consideration of present practices in the country and expected development as well as interconnections with neighbouring countries.

2.3.1.4. Summary of results

2.3.1.4.1. Long-range energy forecasts

The main results of the three scenarios considered in the study are presented in Table 2.X. The demand for final energy is almost equivalent in all three scenarios ranging from 81 to 87 GW·a in 2015 (Fig. 2.11), 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 familiar pattern of development for all three scenarios (Fig. 2.12): 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 predominance 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 petro-chemical 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. This is illustrated in Fig. 2.13, which shows the electricity demand both as total and per capita.

TABLE 2.X. ENERGY DEMAND FORECASTS ACCORDING TO THREE SCENARIOS

	1979	1985	1990	1995	2000	2015
'LOW' SCENARIO						
Final energy, GW·a	8.1	14.9	22.5	32.5	44.2	80.6
Growth rate[a], %/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], %/a	–	2.4	12.4	10.7	9.3	7.4
Electricity, % of total	7.8	8.6	10.4	10.0	9.4	10.4
'MEDIUM' SCENARIO						
Final energy, GW·a	8.1	15.0	22.8	33.2	45.4	83.0
Growth rate[a], %/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], %/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
'HIGH' SCENARIO						
Final energy, GW·a	8.1	15.2	23.2	33.8	45.9	86.9
Growth rate[a], %/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], %/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

[a] All growth rates are calculated from the base year 1979.

The electric power demand to be satisfied in each scenario was determined directly from the MAED results leading to peak demands (in MW) of:

	1979	1986	1990	1995	2000	2015
Low scenario	905	2101	3410	4713	6 258	14 249
Medium scenario	905	2300	3862	6342	8 808	19 119
High scenario	905	2648	4897	8205	12 879	29 366

and the respective annual load factors increase over the study period.

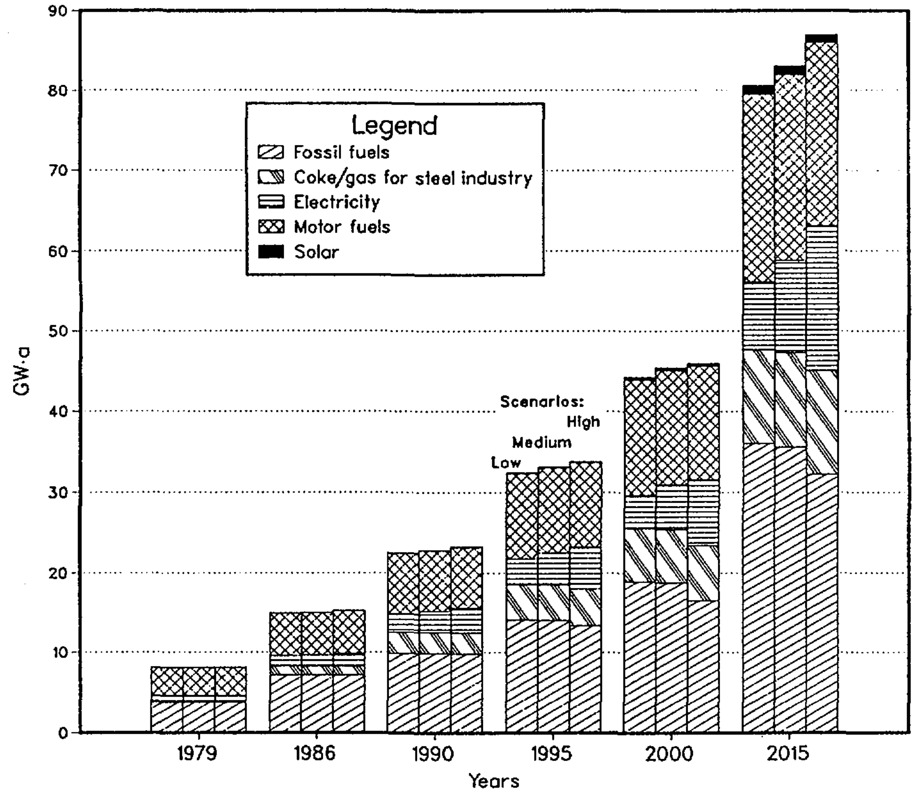


FIG.2.11. Energy and nuclear power planning study for Algeria: breakdown of total demand for final energy by energy form.

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

The principal results are summarized in Table 2.XI and shown in Figs 2.14–16. In terms of capacity additions, up to the 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 Fig. 2.14). Nuclear power appears only in the optimum expansion programme for the high scenario from 2003.

Two important aspects related to the optimum solution for each scenario were considered of prime interest owing to their repercussions on Algeria's economy: the capital investments and the requirements for natural gas (a principal source of revenue for the country) imposed by these solutions, which are shown in Figs 2.15 and 2.16.

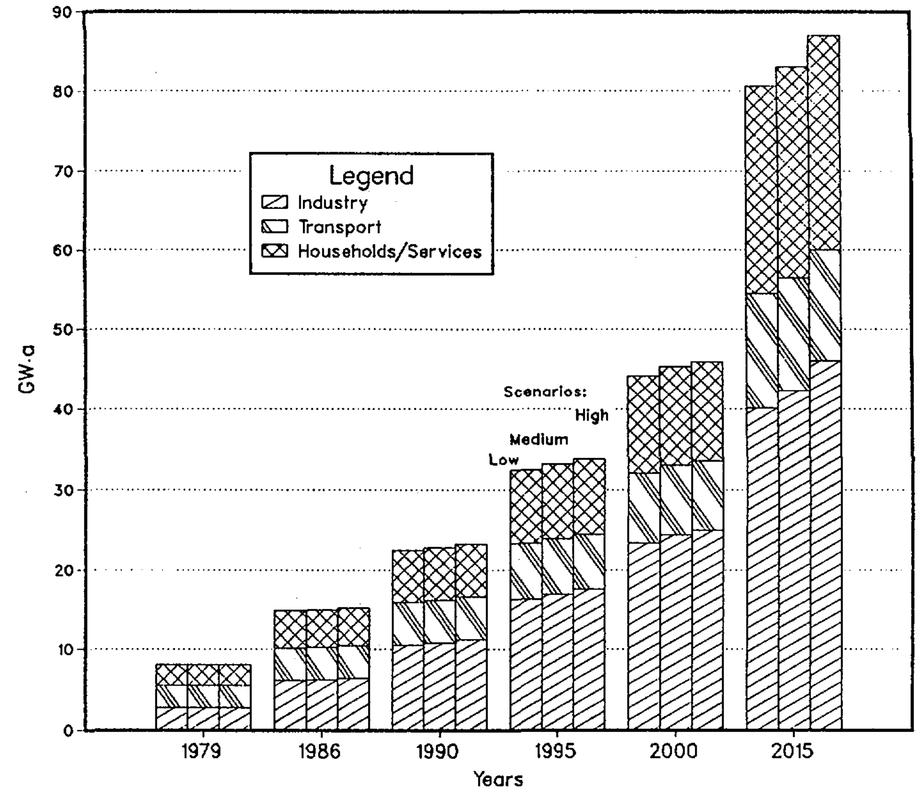


FIG.2.12. Energy and nuclear power planning study for Algeria: breakdown of total demand for final energy by economic sector.

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

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

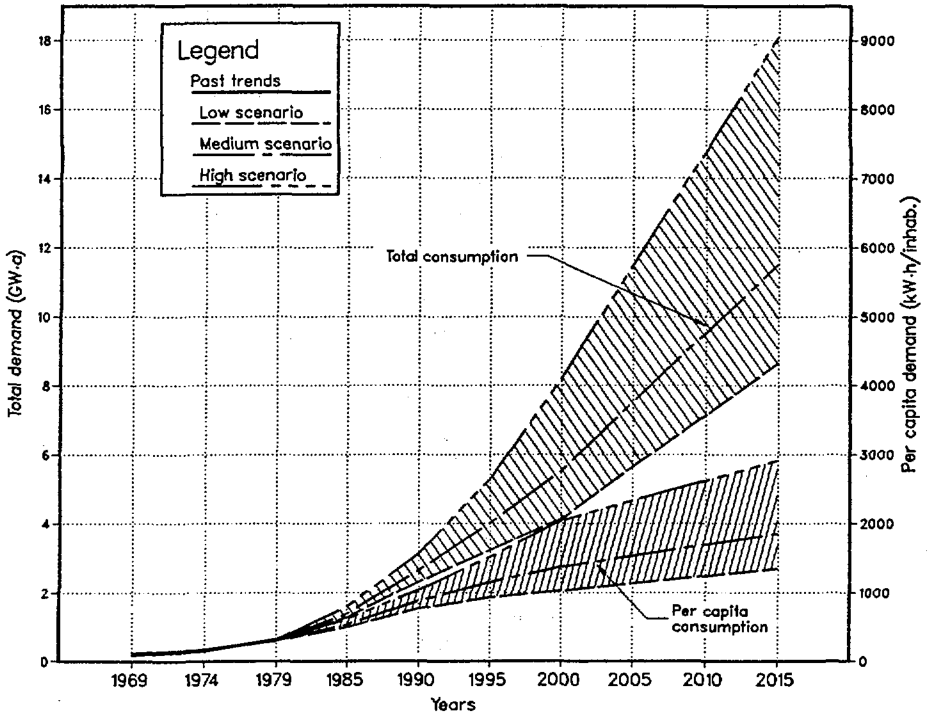


FIG.2.13. Energy and nuclear power planning study for Algeria: trends in total and per capita demand for electricity according to three scenarios.

2.3.1.5. 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 them on the country's facilities. The national team of experts was adequately trained in the use of these models for energy and electricity planning.

Some effort to improve the analytical methodologies may arise from the experience gained with the Algerian experts in 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 overcoming some weaknesses of the models identified during the study.

2.3.1.5.1. Energy forecasts

In qualitative terms the study was not confined to providing figures on electricity consumption but placed these figures in a global energy context,

TABLE 2.XI. DEVELOPMENT OF ELECTRICITY GENERATING CAPACITY AND ROLE OF NUCLEAR POWER BY SCENARIO*

Low scenario	Medium scenario	High scenario
16 575 MW(e) installed between 1986 and 2015 including:	23 550 MW(e) installed between 1986 and 2015 including:	38 025 MW(e) installed between 1986 and 2015 including:
–	–	14 400 MW PWR
11 100 MW GS	17 100 MW GS	13 800 MW GS
5 475 MW GT	6 450 MW GT	9 825 MW GT
Maximum annual capital investment in 2010: 4 354 $\times 10^6$ DA[a] (1979) i.e. 0.7% GDP	Maximum annual capital investment in 2009: 4 024 $\times 10^6$ DA (1979) i.e. 0.8% GDP	Maximum annual capital investment in 2009: 9 979 $\times 10^6$ DA (1979) i.e. 1.7% GDP
Cumulative capital investment: 61.5 $\times 10^9$ DA (1979)	Cumulative capital investment: 85.5 $\times 10^9$ DA (1979)	Cumulative capital investment: 188 $\times 10^9$ DA (1979)
Annual requirements of natural gas in 2015: 18.2 $\times 10^9 m^3$	Annual requirements of natural gas in 2015: 24.6 $\times 10^9 m^3$	Annual requirements of natural gas in 2015: 19.2 $\times 10^9 m^3$
Cumulative requirements of natural gas: 279 $\times 10^9 m^3$	Cumulative requirements of natural gas: 379 $\times 10^9 m^3$	Cumulative requirements of natural gas: 416 $\times 10^9 m^3$

* Including only capacity additions made by the expansion programme, i.e. firmly committed additions are not considered.

[a] DA: Algerian dinar.

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

identifying the factors that 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, MAED-2, is under way).

In quantitative terms, the three scenarios largely covered the spectrum of possible trends in the electricity sector. It would be illusory to try 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. Nevertheless, the final energy demand and, more specifically, the electricity demand will continue to show a marked increase during the next 20–30 years from the combined

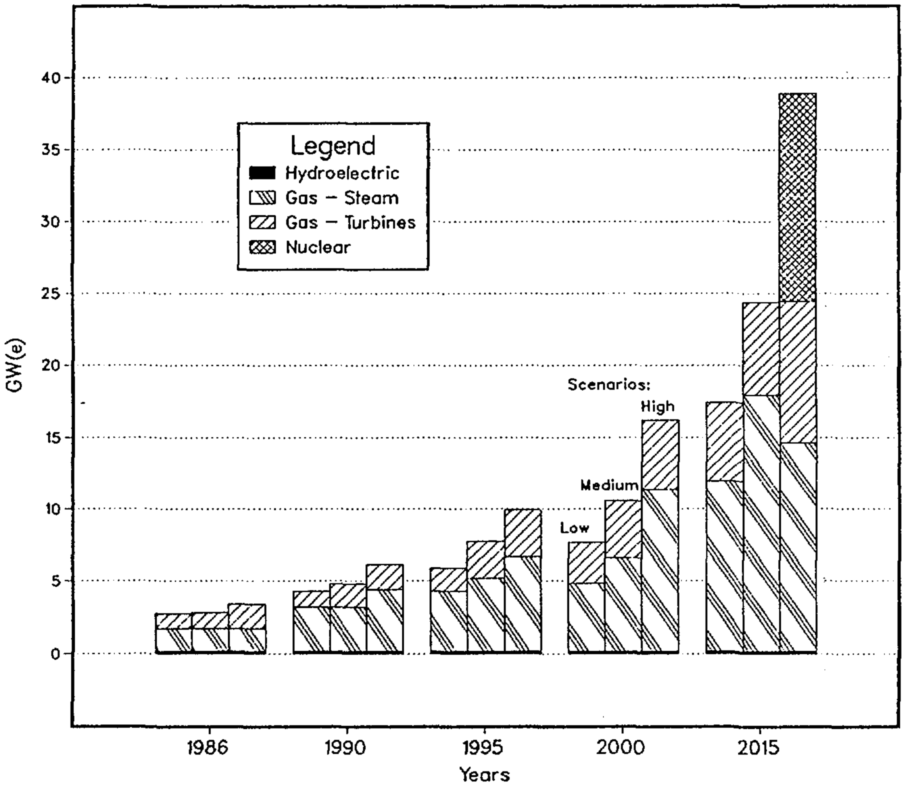


FIG.2.14. Energy and nuclear power planning study for Algeria: development of installed capacity by type of power plant according to three scenarios.

effects of a determined development policy, strong population growth and an increase in energy demand as a result of higher living standards.

2.3.1.5.2. Expansion of generating capacity and the opportunity of introducing nuclear power

The study was made using the WASP model, a methodology that has become traditional as a result of its widespread application and distribution by the IAEA. The procedure still retains its originality because it refrains from providing final answers which would soon become obsolete owing to 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 alternative

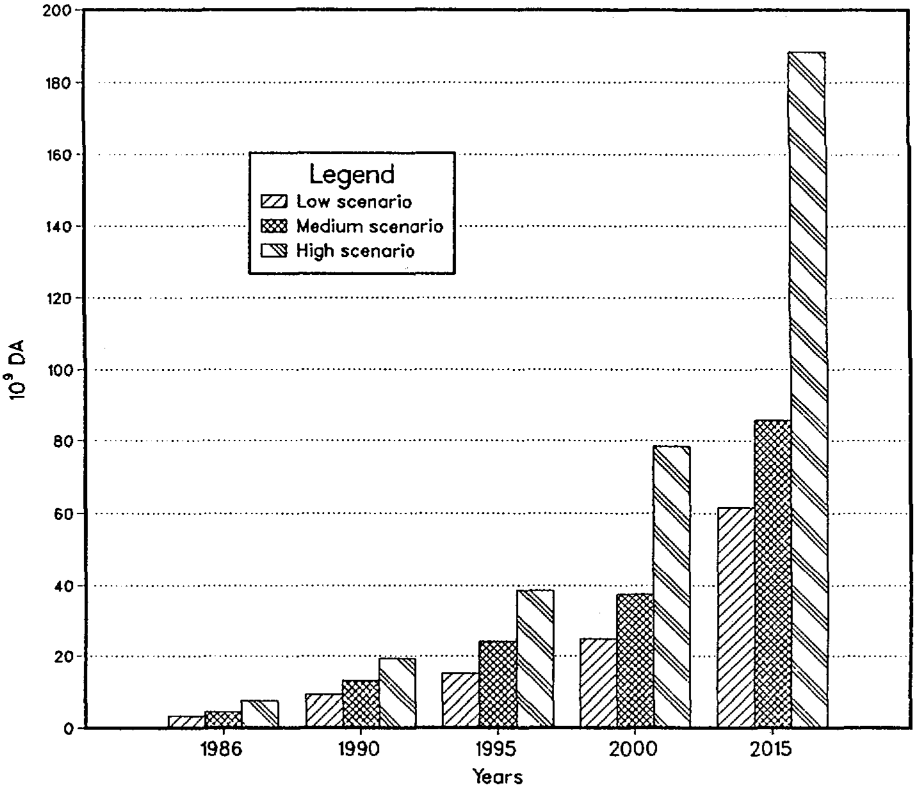


FIG.2.15. Energy and nuclear power planning study for Algeria: total cumulative investments in electricity generation according to three scenarios (DA: Algerian dinars).

studies were chosen with a view to helping to clarify the debate on this important subject and assisting the decision-making 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 investment.

If it is decided to install nuclear generating capacity in Algeria, it must be borne in mind that this is a complex technology whose introduction requires most careful preparations and close co-ordination between all sectors concerned. Among the most important issues are: setting up an institutional framework tailored to fit the specific requirements of this technology; training personnel in order to guarantee that sufficient qualified staff are available to participate in all the phases

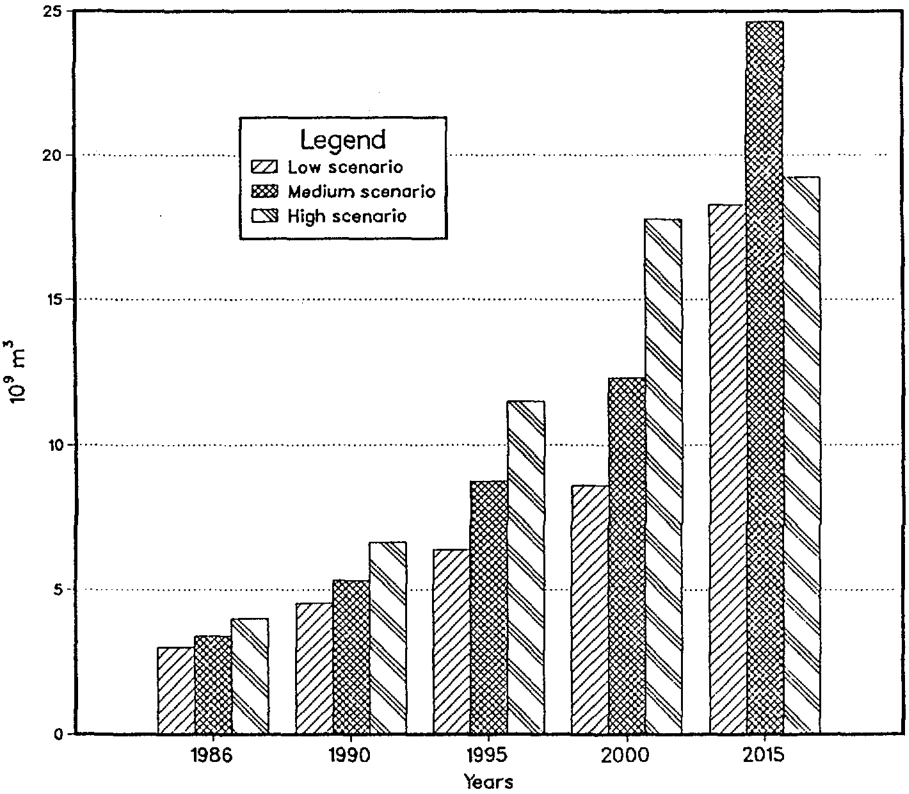


FIG.2.16. Energy and nuclear power planning study for Algeria: annual requirements of natural gas according to three scenarios.

of a nuclear power programme; availability of funds to support the programme; appropriate development of the national industry to secure its participation in the construction of nuclear power plants; search for suitable locations; and structure of the electric power network.

2.3.1.5.3. Recommendations for follow-up studies

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

Further analyses and studies will probably be suggested, and some kind of technical assistance may be requested from the IAEA in the near future. In this respect, additional sensitivity studies should be carried out to analyse the effect on the proposed solutions of major changes in the hypothesis chosen, specifically with respect to the price of natural gas, the investment costs of nuclear and conventional plants, and an 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.

Some other studies should also be undertaken to analyse the impact of introducing nuclear energy into the country, in particular:

- 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,
- Balance of payment conditions,
- Selection of suitable types and sizes of nuclear reactors,
- The choice of nuclear fuel cycle and national participation in the nuclear programme.

2.3.2. US Department of Energy Country Energy Assessments

An initiative of the US Government in working with developing countries on energy planning was known as the Country Energy Assessment (CEA) Program. The aim of the Program was to assist developing and industrializing countries to acquire and/or improve the analytical skills needed to conduct comprehensive national energy planning. The CEA Program was designed as a joint effort between the US Government and the host country government. The first two assessments were conducted in Egypt and Peru in 1978. The next three were performed in Portugal, the Republic of Korea, and Argentina in the period 1979–1981. Owing to US budget restrictions the Program was discontinued in late 1981.

The US efforts were managed by the Department of Energy (DOE) under the policy guidance of the Department of State. The US team consisted of a DOE Country Director and a technical staff drawn from the DOE national laboratories, the US Geological Survey, other US government agencies, and private contractors. The first two assessments were managed directly by DOE, and the other three by Argonne National Laboratory, a DOE facility.

The host country team was led by an Executive Director appointed from one of the government ministries. A co-ordinating committee, with representatives from agencies with an interest in energy issues, was also usually formed. A multi-disciplinary technical analysis team was formed to work directly with the US technical team and to learn the analytical procedures to be used.

US participation in the assessment amounted to about 10–15 professional person-years per country over an 18–24 month period and was funded by the US Government. Host country participation was approximately equal considering all the organizations involved. The host country paid all expenses of their own personnel.

One of the prime objectives of the assessment process was to transfer the analytical skills to the host country team. This was done through close working relationship between the country team and the US technical team. Formal training courses in the use of the analytical tools were also held. All the computer-based procedures were mounted on host country equipment and checked out.

2.3.2.1. Methodology

The methodology used in the assessment process was essentially identical to that described in Section 2.2 and represented by Fig. 2.1. There was a division of responsibilities between the US and host country teams in carrying out the various tasks. The economic growth analysis (shown in Fig. 2.1) was conducted primarily by the host country team. The team developed alternative growth scenarios that were used as the basis of the projections. The host country team decided upon and implemented the growth analysis methodology. In some cases a detailed macroeconomic model was used to prepare the projections; in others a simple GNP growth rate was specified.

To complete the database assembly for the assessment, the US team visited the host country for a period of 6–8 weeks. Visits were set up between US and host country counterparts to identify data available and to develop a consensus on the information to be included in the assessment. A series of database reports was prepared documenting the information in the task areas: sectoral energy demand, resource evaluation and energy technology evaluation.

The sectoral energy demand data were assembled by the US team with the help of host country counterparts. Specialists in each sector (e.g. industry, agriculture, transport) worked together to develop the current pattern of energy consumption. Of special interest was the disaggregation of the fuel use into useful energy demand categories. As this type of data was frequently not available, some spot surveys were conducted. In each sector the US and host country analysts prepared a base year description of current energy consumption, a disaggregation to useful energy demand categories, a projection of future useful energy demand levels using the economic growth scenarios, and an identification of alternative energy conservation options.

The fossil energy resource evaluation was conducted by a team from the US Geological Survey and host country geologists. The effort focused primarily on the review of existing information. No new geological field surveys were undertaken. In many instances, recorded geological data had never been fully analysed and a great deal of new insight was gained by the exercise.

The energy technology evaluations were divided into fossil energy technologies, renewable resource technologies, and the electric sector. In each area the status of the existing system was reviewed, the performance and costs associated with each system were compiled, and the plans for system expansion identified. In all the countries studied, technologies that were not now in place but which might be viable candidates in the future were identified.

TABLE 2.XII. COUNTRY ENERGY ASSESSMENT PROGRAMME: ALTERNATIVES CONSIDERED

Country	Growth scenarios	Energy conservation option	International energy prices	Energy system configurations
Egypt	(a) Only 1 case used fuel projections	(a) Improved efficiency	Not considered	(a) Maximized use of natural gas (b) Accelerated use of renewable resources (c) Variations in nuclear capacity
Peru	(a) Only 1 case	(a) Improved efficiency	Not considered	(a) Increased use of renewable resources (b) Increased use of hydropower (c) Increased use of coal
Portugal	(a) Baseline growth (b) Higher growth	(a) Moderate conservation efforts (b) Accelerated conservation efforts	(a) High oil, moderate coal (b) High oil, high coal, high nuclear (c) Moderate oil and coal (d) High oil, high coal, low nuclear	(a) Accelerated use of renewable resources (b) Use of domestic refinery capacity (c) Variations in nuclear capacity (d) Use of synthetic fuel technology
Rep. of Korea	(a) High growth (b) Medium growth (c) Low growth	(a) Technology fixed (b) Accelerated conservation efforts	(a) Low prices (b) High prices (c) High oil and coal, low LNG[a] and nuclear	(a) Increased solar technology (b) Use of synthetic fuel technology (c) Unconstrained economic conditions
Argentina	(a) High growth (b) Low growth	(a) Moderate conservation efforts (b) Accelerated conservation efforts	(a) High oil (b) Low oil	(a) Domestic oil and gas pricing policies (b) Accelerated use of renewable resources (c) Imported coal alternatives

[a] Liquefied natural gas.

The integrated analysis group was composed of US and host country energy planners. Their efforts were aimed at putting all the database information into a systematic framework and evaluating alternative scenarios for the development of the energy system. This activity was conducted primarily in the USA with host country planners spending considerable periods of time working with the US team. A series of computer-based models was used to construct supply/ demand balances and to evaluate the impacts of the various alternatives. Among the models used were the Argonne Energy Model (AEM) (a generalized equilibrium model used to develop a market-based projection of energy supply and demand), the Wien Automatic System Planning (WASP) package (an electric sector model), and the Energy Supply Planning Model (ESPM) (a facility construction estimating model). These tools were run in tandem, with the output of one serving as the input of another. The host country planners were trained in the use of these tools and brought them back for installation on their own equipment.

The integrated analysis group was responsible for identifying the alternatives to be studied and for carrying out the analysis of these alternatives. As the country energy assessment was *not* designed to produce a national energy plan, the alternatives evaluated were somewhat more hypothetical than might be used in an actual planning exercise. Nevertheless, some definitive insight into how the energy system might develop was gained.

2.3.2.2. Results of the analyses

All of the assessments have been thoroughly documented [16–20]. Both the database used and the results of the integrated analyses are available. The Egypt and Peru Assessments were the first attempts at such a comprehensive energy analysis. As a result, these studies reflect early perceptions of how to structure such an analysis and use only very simple analytical procedures. The Portugal, Republic of Korea and Argentina Assessments represent a 'second generation' planning methodology and use more advanced techniques. Table 2.XII shows the alternatives considered for each country; they were based on the unique conditions and important issues in each country.

Excluding the Egypt and Peru Assessments, for which only one economic growth scenario was considered, the analyses showed the impacts of different growth rates on the energy requirements of each country (Table 2.XIII summarizes the results). In all cases, some level of energy conservation was considered, hence the elasticity of energy consumption relative to GDP is less than one. It is evident from the results that the economic growth assumptions made have a substantial impact on the energy requirements. It is therefore important to investigate a range of possible growth conditions in any energy planning exercise.

The effects of an energy conservation programme were studied for all the countries (Table 2.XIV shows the results). Some significant benefits can be achieved by implementing a conservation programme. Energy savings from 4.1% to

TABLE 2.XIII. EFFECT OF GROWTH RATE ON ENERGY CONSUMPTION

Country	Planning period	Growth scenario	Average annual GNP growth rate[a] (%)	Base year energy consumption[b] (10^{15} J)	End year energy consumption[b] (10^{15} J)	Average annual energy consumption growth rate over planning period[a] (%)	Energy/GNP elasticity over planning period
Portugal	1977–2007	Baseline growth	4.6	314	989	4.2	0.92
		Higher growth[c]	6.2	314	1299	4.8	0.83
Rep. of Korea	1978–2008	High growth[d]	6.6	1307	8011	6.2	0.96
		Medium growth[d]	4.0	1307	4915	4.5	0.95
		Low growth[d]	3.5	1307	4337	4.1	0.95
Argentina		High growth[d]	4.5	1119	3637	4.0	0.89
		Low growth[d]	1.0	1119	1492	0.096	0.95

[a] The value indicated is the effective annual average over the entire period.

[b] Measured as fuels and electricity delivered to consumers. Portuguese tep = 10^7 kcal = 39.72×10^6 Btu = 41.9×10^9 J. Korean toe = 10^7 kcal = 39.72×10^6 Btu = 41.9×10^9 J. Argentine tep = 1.05×10^7 kcal = 41.667 Btu = 44.0×10^9 J.

[c] High growth scenario assumes accelerated conservation efforts.

[d] No sectoral changes were included in the growth scenarios, hence the energy consumption scales almost directly to the growth.

TABLE 2.XIV. EFFECT OF ENERGY CONSERVATION ON ENERGY CONSUMPTION

Country	Planning period	Conservation programme	Reduction in energy consumption over base case (%)	Energy/GDP elasticity over planning period	
				Base case	Conservation programme
Egypt	1975–2000	Moderate efficiency improvements	4.1[a]	NA[c]	NA
Peru	1976–2000	Moderate efficiency improvements	5.4[a]	NA	NA
Portugal	1977–2007	Accelerated conservation	6.5[b]	0.92	0.88
Rep. of Korea	1978–2008	Accelerated conservation	13.0[b]	0.96	0.89
Argentina	1978–2008	Accelerated conservation	16.0[b]	0.89	0.76

[a] Based on primary resource use.
[b] Based on fuel and electricity delivered to consumers.
[c] NA: not applicable.

16.0% per year in the last year of the planning period were realized. Note that the conservation options studied were based almost exclusively on utilization of higher efficiency equipment. Changes in the general structure of the economy were not studied and could yield even higher savings.

For the Portugal, Republic of Korea, and Argentina Assessments, the effects of changes in the prices of imported energy were evaluated. For Portugal and the Republic of Korea, which are both almost exclusively dependent on imported oil, the range of prices studied showed some shifts between imported oil and coal. However, imported coal seemed to be a viable alternative to oil under all conditions studied. Even when coal was assumed to grow in price at a faster rate than oil, it retained an economic edge because of its current lower cost. The results implied that coal can be an economically competitive replacement for oil even when the additional infrastructure and handling costs are included. Further detailed engineering feasibility studies seem to be appropriate.

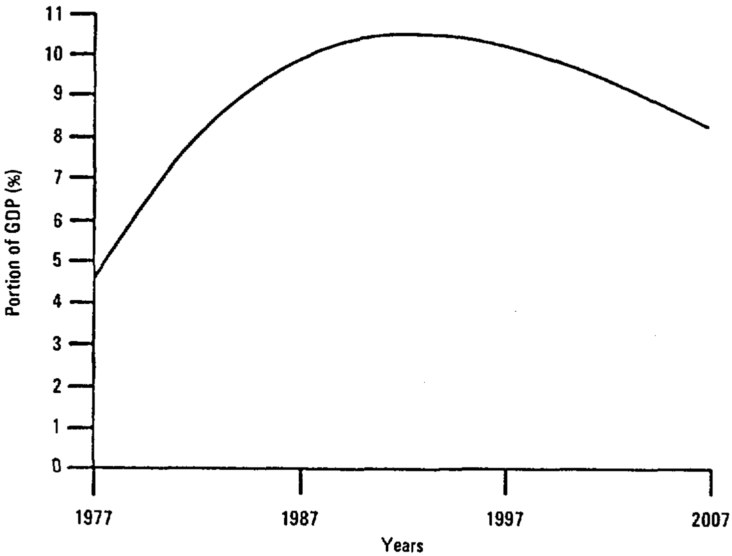


FIG.2.17. Fuel imports as a function of GDP: Portugal.

Different structures of the energy supply system were studied in each country. Restrictions on imported petroleum products, maximizing the use of domestic resources, domestic pricing policies, and changes in policy on the use of nuclear power were among the alternatives studied. The variations are too numerous to detail here. One result did, however, seem to appear with regularity. The role of renewable resource technologies, particularly solar systems for residential and industrial use, seems to be limited by their high cost. In the countries studied, solar systems required cost reductions, either by direct subsidy or more efficient manufacturing techniques, of 25–50% to achieve any significant market penetration. It should be noted that this is from a national point of view and does not consider any local conditions that might make the situation different. Nevertheless, to compete effectively, solar systems will require significant cost reductions and/or policy decisions to implement them in spite of higher costs.

In addition to the energy supply/demand results for each of the alternatives studied, an impact analysis was conducted. The analysis considered the effects of each of the alternatives on the economy in general. The parameters studied for each alternative were the prices of delivered fuels and electricity, the fuel import bill, the capital costs of new energy facility construction, the operating costs of the energy system, labour requirements for construction and operation of the energy system, and balance of payments implications. One interesting result was the impact of fuel imports on GDP. Figures 2.17 and 2.18 show fuel imports as a function of GDP for Portugal and the Republic of Korea respectively.

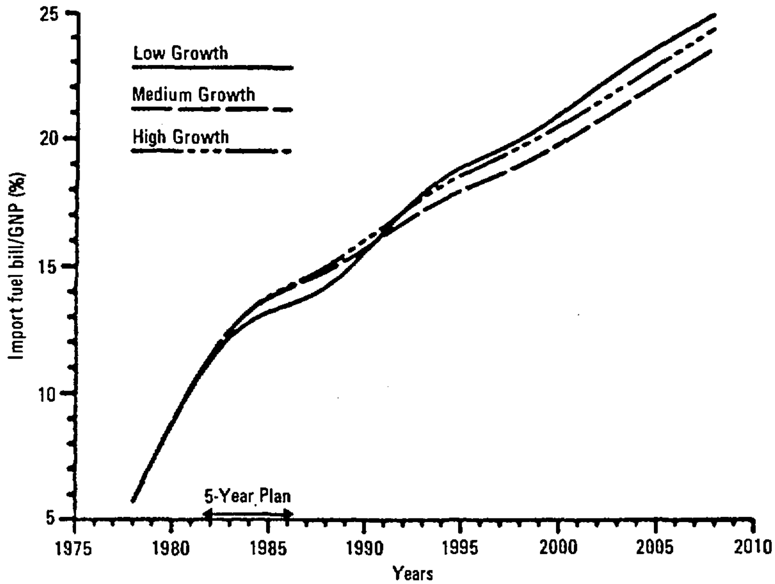


FIG.2.18. Fuel imports as a function of GDP: Republic of Korea.

These results are heavily dependent on the import price assumptions; nevertheless, they indicate that these countries, and probably most other developing countries, are faced with having to spend larger and larger portions of their GDP on energy imports.

2.3.2.3. *Evaluation of the assessment process*

Because the Country Energy Assessment Program was not intended to result in a national energy plan for the co-operating countries, it must be evaluated by how well it achieved the objectives of providing assistance in energy planning procedures rather than by whether or not the specific results are being utilized.

The analytical tools used in the assessments were transferred to the participating countries, and training programmes were held to assist in their implementation. From preliminary reports, at least four of the five countries participating in the assessments are actively exercising these tools to update the analyses for actual national energy planning studies. Because of variations in capability and experience, there have been varying degrees of success in using the tools. Nevertheless, there is a concerted effort to improve upon the analytical procedures used prior to the assessment.

Administratively, the energy assessment provided an opportunity for the various organizations dealing with energy problems to work together, exchange information and conduct joint analyses. In some cases, the assessment activity was the first time this had happened. In one country, it was decided to create a new permanent institutional structure consisting of a multidisciplinary team to conduct future energy planning studies. This organizational recognition of the multifaceted nature of the energy problem is an important step in the energy planning process.

The assessment process showed that a reasonably comprehensive analysis of energy issues can be conducted in a developing country in spite of the problems of data availability and reliability. It was possible to assemble enough information and conduct a relatively complete analysis with the available data. None of the participants would claim that the information is completely accurate or that there are not significant gaps needing to be filled. The exercise nevertheless provided valuable insight into the dynamics of the energy system and is giving planners a better perspective on the important issues.

One weak spot in the assessment was the short-term, intensive data-gathering on the part of the US team. It appears that this activity would be better left to the host country team under the guidance of experienced planners. There does not appear to be as great a need as was at first thought for US personnel to be involved in the actual performance of large parts of the analysis. More emphasis should perhaps be placed on training and technology transfer. The approach used in the CEA programme was dictated by the nature of the programme itself, i.e. it was a co-operative government-to-government activity.

It should be kept in mind for any such future activity that the role of the host country participants cannot be overemphasized. The CEA programme, more than most other such studies, tried to avoid the approach of an outside consultant performing a study for the country. The programme succeeded, up to a point, in being a truly co-operative effort, with the host country personnel making major contributions to the data-gathering, the analysis, and the preparation of the report. Such an approach should be encouraged and developed in order to enhance the ability of developing country planners to conduct such studies on their own.

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Chapter 3

ELECTRIC SYSTEM PLANNING

This chapter introduces the complexities of planning the electric system. The components of electric system planning are reviewed and the important issues discussed. The areas emphasized in this guidebook are defined in relation to electric system planning in general. Several topics are introduced which are covered in some detail in the remaining chapters and appendices.

3.1. MEANING OF ELECTRIC SYSTEM PLANNING

3.1.1. Relationship to overall energy planning

As discussed in Section 2.2.6, electric system planning is linked to overall energy planning primarily through the demand forecast, which should account for anticipated economic activity, population growth, and other driving forces for changes in electricity demand over time. The benefits of linking the two planning activities include (a) avoiding duplication of effort (such as making independent sectoral economic projections), (b) consistency of assumptions for important independent variables, and (c) understanding the basis for the forecasts. This is not to say that electric system planners should accept without question assumptions made by others. Sensitivity analyses of important parameters are often the most useful result of electric system planning studies.

Additional connections with overall energy planning could include financial analysis and use of resources. If financial constraints exist, such as limited availability of capital for construction of new projects, the importance not only of co-ordination with the overall energy activity but also of planning other capital-consuming activities, is more evident. Limited fuel resources (e.g. natural gas that could be used for space heating, industrial boilers or power generation) justify some co-ordination of these planning activities. This also applies in the case of adequate water management when there are simultaneous needs for navigation, irrigation and hydroelectric power generation. Thus, studies of electric system expansion for an entire country should recognize that this activity is not totally independent of other planning and analysis activities. Links with overall energy planning may be less necessary for a utility serving a small part of a nation's demand, but some effort to develop load forecasts, for example, that make use of national or regional economic projections is appropriate.

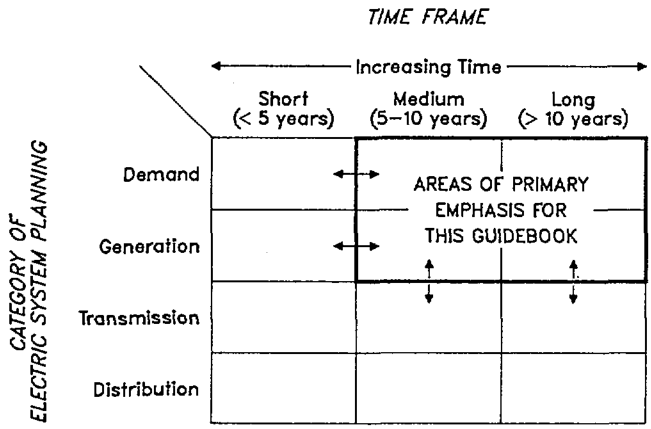

FIG.3.1. Categories of electric system planning and time frames for analysis. ⟷ *implies intercellular interactions to be dealt with.*

3.1.2. Dimensions of electric system planning

Now that electric system planning has been put into the context of overall energy planning, the dimensions of electric system planning can be defined. The categories of electric system planning and the appropriate time frames for different types of analysis are reviewed, and the way the subject is treated later in the guidebook is explained.

3.1.2.1. Categories of analysis

Electric system planning encompasses a broad collection of activities spanning several time horizons and can be divided into categories of analysis such as demand, generation, transmission and distribution. Each category of analysis may be carried out for what is defined in this guidebook as a short time frame (e.g. less than five years), a medium time frame (e.g. five to ten years), or a long time frame (e.g. more than ten years), and is shown graphically in Fig.3.1. This does not imply that electric system planning can simply be divided into twelve independent activities; rather, it is conceptually convenient to think of these categories because the different problems to be faced and the different analytical techniques to be used depend, in general, on the time frame and the category of electric system planning. For example, studies of the generating system during the next year or two usually involve limited options for changing the generating system, such as deferring retirement of a unit. In contrast, studies of the evolution of the generating system during the next 25 years typically involve substantial changes in composition for the system. Therefore, different types of models and levels of data detail are needed for the two types of study.

The areas mainly emphasized in this guidebook are also shown in Fig.3.1. Most of the material is focused on long-term planning of the generating system; medium- and long-term demand analysis and medium-term generation planning are covered in less detail.

The other combinations of categories of electric system planning and time frames receive significantly less attention in this guidebook, not because they are unimportant but because treatment of these topics could easily require one or more additional guidebooks. However, some of the interactions that must be considered in conjunction with expansion of the generating system are discussed here. For example, frequency stability and transmission system requirements and constraints can affect the optimum long-term expansion for a generating system. Many of the principles and considerations in the guidebook are also relevant to generating system analysis for a short period of time. However, the models used for analysis (such as planning fuel purchases during the next two years) usually represent the generating system in more detail than is practical for a study of long-term expansion options. Important topics in the study of short-term problems, such as details of the existing maintenance and nuclear refuelling schedule, receive little attention here.

3.1.2.2. Objectives of electric system planning

Simply stated, the primary objective of a public utility company is to adequately meet the demand for electrical power at the minimum cost (the definition of 'adequate' as used here and the ways in which to account for sufficient reliability of supply are additional complexities discussed in Section 3.2.4). Of course, the utility must conform to existing constraints, such as financial limits, domestic resource availability, and government policies. Thus, 'minimum cost' usually means minimum cost subject to a set of financial, resource, technical, environmental and political constraints, and these constraints define in turn whether the minimum refers to minimum costs for the utility, the economy, or a combination of both. The careful planning and co-ordination of investments in the generation and transmission system as a whole is an important step toward a satisfactory overall performance of a power system.

Albouy et al.[1] have identified four basic questions to be answered in the course of the planning process. They are (slightly modified):

- WHAT capacities to install to ensure an appropriate level of reliability?
- HOW to pick the best combination among the different technologies at hand now and later on?

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[1] ALBOUY, Y., JOLY, G., LAUNAY, M., MARTIN, P., CRISTERNA, R., SALINAS, E., SOSPAVON, F., URDAIBAY, C., "An integrated planning method for power systems – Parts I, II, III", presented at 9th Power Industry Computer Applications Conf. (PICA), New Orleans, 1975.

– WHERE to locate this new equipment?
– WHEN is the proper time to incorporate them into the system?

Briefly stated, major decisions in expansion planning of the generating system must consider alternative generating unit sizes, types of capacity, timing of additions, and locations. Obviously, these interrelated questions represent a non-trivial problem involving many complexities, as outlined in the next section. Most models for long-run optimization of generating systems attempt to provide reasonable answers to at least three of these questions (WHERE? being the usual exception). However, just answering three of the questions requires modellers to make many compromises between precise representation and practical considerations.

3.1.2.3. Complexities of electric system planning

A major complexity facing the electric system planner is the uncertainty introduced in studies over a long time horizon. Studies of optimal expansion strategies of necessity cover a long time horizon because of the long lead times for constructing new capacity and because of the need to account for the long-run system effects of potential new capacity. For example, the short-run optimum for a generating system is often to add low capital cost/high operating cost options, such as gas turbines. However, when long-term operation of the generating system is taken into account, units with higher capital costs but lower operating costs become more likely to enter the optimum solution, i.e. the savings in system operating costs attributable to the high capital cost unit is not sufficient to override the extra capital cost if only relatively few years are considered but is often sufficient if a longer time horizon is considered.

The need for a long time horizon to optimize the generating system is indicated in Fig.3.2, which shows typical time ranges for various types of planning. The load dispatcher is primarily interested in very short-term estimates that will help in the operation of the existing system. Hourly and daily estimates are required for system operation, with weekly and monthly estimates to cover maintenance scheduling. Somewhat longer time ranges for planning are appropriate for various kinds of financial planning and determination of rates (tariffs). Planning and construction of new peaking and cycling generating facilities require several years. Planning and construction times are significantly longer for nuclear, hydroelectric and large fossil-fired units. Optimization studies of generating systems must therefore extend over very long time horizons to incorporate the system effects of all types of potential generating capacity.

Since long time horizons are required for optimizing the generating system, uncertainties can be particularly great concerning electrical demand, improvements in technological performance, fuel availability and cost, financial conditions, and other important factors. Forecasts of key parameters over long

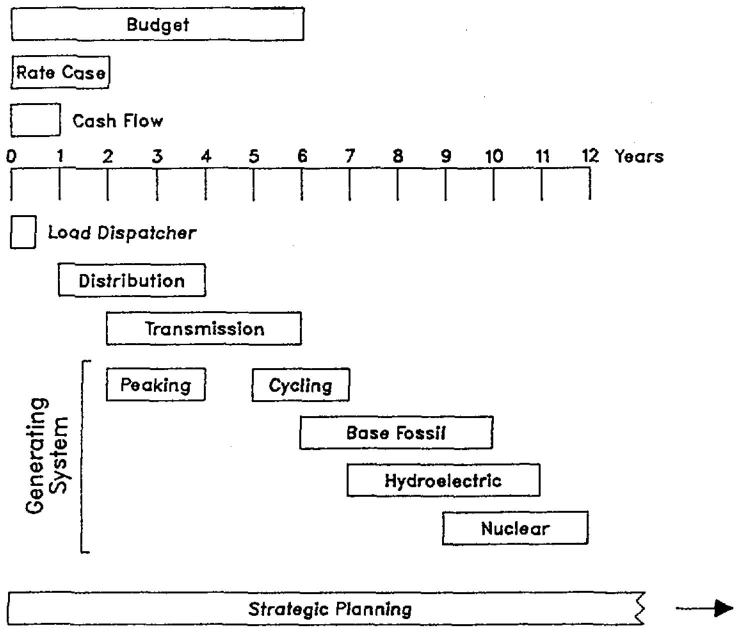

FIG. 3.2. Typical time ranges for planning.

time periods are difficult to make. The inherent uncertainties in such forecasts should not be forgotten and, if possible, the effects of uncertainties in key parameters should be examined through sensitivity analysis.

The use of long time horizons creates another practical difficulty for the generation planner because the system operation must be calculated for so many possibilities over so many years. It is desirable to calculate the system operating costs during as short a time period as possible in order to properly represent important generating system characteristics such as the seasonal variation of load and the scheduled maintenance of generating units. However, if an optimization model is to calculate many thousands of possible combinations of new generating units over many years, the time period for analysis within a year must often be as long as three months. After narrowing the possibilities for expansion of the generating system, this time interval can be shortened, or a more detailed model can be used, to make sure that the longer time interval does not introduce significant inaccuracies in the representation of generating system operation.

The number of potential alternative expansion pathways becomes unwieldy in only a few years from the starting point even for a system with a relatively low growth rate and a limited number of types of generating units that can be added. The calculational burden becomes impracticable when the multiple calculations within the year (e.g. monthly or seasonal) of system operating costs for several hydroelectric possibilities are considered. Methods for scaling the massive problem down to a manageable size are therefore needed. Various models use different methods to become practical. Judgements must be made by the analyst to determine which types of approximations and constraints are reasonable for a particular generating system.

Another complexity arises from the stochastic nature of the electric supply/demand system. Electric supply can be affected at any time by random breakdowns of generating equipment or, on a longer time scale, by the availability of water for hydroelectric generation (see Chapter 8). Expected variation in supply of hydroelectric energy is a difficult problem that must be confronted in planning generating systems. Electric demand also has stochastic components; for example, in some countries, a portion of demand is sensitive to weather (see Chapter 4).

3.1.2.4. Utility development philosophies

The development and expansion of electric power systems usually take place within a given set of basic goals and wider objectives provided by a national or local energy policy. Where such policies do not exist, the utility itself, in determining its future needs, must consider the proper role of electrical energy in a broad context.

3.1.2.4.1. Objectives

A typical power utility development philosophy is to supply the electrical energy requirements of its customers at the lowest possible cost consistent with appropriate levels of reliability and safety. This rather simplistic approach may be complicated by the effects of, for example, the desire to:

- minimize dependence on foreign sources of fuel for fossil-fired generating units for security reasons even though such supplies may be cheaper than internally available fuel;
- minimize the use of prime fuels for power generation;
- increase domestic industrial participation in the construction of power stations;
- influence customer consumption through its rate structures.

3.1.2.4.2. Isolated versus interconnected operation

At some point in power system development planning, the question usually arises whether or not to consider interconnecting with one or more neighbouring utilities. The basic question is:

Is the utility better off having total control of its development and operational decisions, with associated benefits and problems or is it better off being interconnected with adjacent power systems and gaining increased flexibility and potential for reducing its investment and operating costs, even at the expense of some loss of autonomy over its decision-making processes?

This subject has been debated by power utilities for many years and the conclusion has usually been that the benefits – particularly the increased operating flexibility associated with interconnected operation – outweigh any negative arguments.

The degree of dependence placed on adjacent power systems varies widely, depending, among other things, on how much confidence a utility has in its neighbour's willingness to operate (both short and long term) in accordance with planning and operating principles agreed in advance.

Some specific opportunities that are possible with increasing confidence in the neighbouring systems include:

- Sharing reserves in emergencies.
- Hour-by-hour sale and purchase of surplus interruptible[2] energy (profits or savings resulting from such transactions directly offset the revenue requirements from internal customers).
- Joint planning to minimize reserves while maintaining the same level of reliability.
- Sales or purchases of short-term (days to a few years) surplus non-interruptible capacity with its associated energy.
- Entitlement arrangements for specific units. Such arrangements allow the installation of a generating unit larger than otherwise possible in one of the systems with a portion being sold to the neighbouring systems until such time as the installing utility can accept the operating and financial risks associated with poor unit performance entirely within its own system. Furthermore, such an arrangement allows the installing utility to obtain the economy of scale associated with the larger unit size (i.e. the reduction in cost per unit of capacity that typically accompanies increases in unit size) earlier than would otherwise be possible and avoids escalation of capital costs of an otherwise delayed in-service date for such a unit size. Due consideration must, of course, be given to the trade-offs to be made between economies of scale and system reliability.

[2] Sales can be terminated by the supplier for specified intervals, e.g. because of a sudden equipment failure in the supplier's system.

- Joint ownership of generating units. This allows the installation of units larger than otherwise possible with all their associated benefits from economies of scale. Such arrangements do, of course, require complete trust that the installing utility – perhaps in another country – will honour its long-term contractual obligations.

The most important ingredient for developing and maintaining successful relationships between interconnected utilities is the adherence to ethical operating practices at all times. That is to say that prior commitments must be upheld even though the benefits or costs may have changed dramatically in the meantime.

3.1.2.4.3. External considerations

There may well be instances where the power utility can, from time to time, use its unique characteristics to help attain the basic goals and wider objectives of a broader energy policy.

Consider, for example, a country that may have large natural gas reserves which, because of inability to create large enough early-year markets to support the financing, have remained undeveloped. The power utility, if it has fossil-fired generation, can, with a minimum of conversion costs, modify its boilers to burn natural gas. As the natural markets increase over time, the utility consumption can decrease.

To illustrate this concept further, suppose a country wishes, for security reasons, to make its natural gas resources available to all its citizens as a backup against the possible curtailment of some foreign fuel supplies. Such natural gas can be fed into the power utility's boilers and distributed through its transmission and distribution system to every industry and private residence in the country in an emergency.

3.2. ISSUES FOR PLANNING GENERATING SYSTEMS

The previous section presented some overall principles and complexities of system planning. This section examines the major issues in the development of a long-term expansion plan for the generating system.

3.2.1. Demand

The forecast of electrical demand is clearly one of the most important components of a generating system analysis. The forecast typically must be for power (kW), energy (kW·h) and load variation for time intervals within a year, such as a month or season, for all years of the study. If a great deal of effort is to be devoted to analysing the alternative expansion possibilities, the demand forecast should also receive a significant effort.

There are two distinct types of uncertainty in demand forecasting. First, there is the uncertainty that results from the randomness of the load at any time because of, for example, weather conditions. This type of uncertainty is, of course, a major concern for the load dispatcher. The other type of uncertainty is associated with the estimate of future demand, i.e. the estimate may be too high or too low. Underestimating future demand can create serious difficulties because service dates for new facilities can seldom be advanced appreciably. The result may be a generating system with low reliability and the inability to serve some portion of demand. Overestimating the demand is also undesirable because excess generating equipment imposes increased costs on the system. Service dates for new facilities under construction can be delayed if load growth has been overestimated, but such delays can be very expensive. Chapter 4 presents in some detail the considerations involved in forecasting future electrical demand.

3.2.2. Technology options

Various technologies are currently available as candidates for expanding electrical generating systems. Each has a unique set of characteristics that must be considered from a system viewpoint to determine the mix of future additions that provides the best outcome for the stated objectives for expansion. In addition to existing technologies, long-term studies of generation expansion must consider whether advanced technologies will become available and, if so, what their costs and characteristics will be.

Power generation technologies may be classified into existing major options and potential future options. The primary existing options are summarized in Table 3.I. Several types and sizes of nuclear, fossil-fired and hydroelectric plants are currently available (Chapters 8 and 9 and Appendix G contain a description and technical data for the existing major options). Advanced versions of each technology are also being developed, such as breeder reactors, fluidized-bed combustion of coal, more efficient combustion turbines, and combined cycle based on coal gasification coupled with various combinations of steam turbines, fuel cells, combustion turbines and magnetohydrodynamic generators.

In addition to advanced versions of existing technologies, the generation system planner must consider potential future options, such as those listed in Table 3.I. Some of these technologies are currently in use in special situations, such as geothermal generation in Australia, the Philippines and western USA. Several types of wind turbines are being tested world wide, and significant efforts are being devoted to reducing the cost of photovoltaic generation. However, these options cannot at present be considered as

TABLE 3.I. TECHNOLOGY OPTIONS FOR ELECTRICAL GENERATION

Type of power station	Primary energy source
Existing major options:	
Nuclear	Uranium
Fossil-fired steam	Coal, oil, natural gas
Hydroelectric	Falling water (solar)
Combustion turbines	Distillate oil, treated residual oil, natural gas
Diesel engines	Diesel fuel (oil)
Combined cycle (steam and combustion turbine)	Oil or natural gas
Pumped storage (hydroelectric)	Falling water for generation and other generation sources in the system for pumping
Potential future options[a]:	
Steam turbines	Wood, urban waste, biomass, solar thermal, geothermal
Fuel cells	Hydrogen-rich gas (can be obtained from light distillate fuel or other liquid or gaseous fuels)
Photovoltaic	Solar
Wind turbines	Wind (solar)
Ocean thermal energy conversion	Ocean water temperature difference with depth (solar)
Tidal power	Ocean tides
Storage (battery, compressed air)	Other generation sources in the system

[a] In addition to advanced versions of existing major options.

serious candidates to serve large fractions of new demand in the near future. For the longer term, judgement must be made on the likelihood of commercial success for these options as well as for the advanced versions of existing major options.

Evaluation of hydroelectric potential presents an additional complication. In mixed hydrothermal systems, detailed simulations and analysis of hydroelectric possibilities are needed. One obvious reason for this is that the operation of one hydroelectric generating unit may affect the capacity and energy available from another, i.e. hydroelectric units cannot be considered as completely independent generation sources. Another difficulty is how variation in year-by-year water availability is taken into account. These important practical considerations are discussed in Chapter 8.

3.2.3. Economic evaluation

A fundamental aspect of any economic evaluation is the time element, since implementation time and economic lifetime of a generating unit require a certain number of years: a particularly large number in the case of nuclear units, where the overall period to be considered usually varies between 30 and 45 years (typical values are 10 years for implementation and 30 years for economic lifetime).

A key concept in understanding the basic principles of economic evaluation is the time value of money, i.e. how streams of costs or incomes (or alternatively of produced electricity since it generates an income) occurring through time can be compared on an equivalent basis. The relationship between time and money is affected by two distinct factors:

(a) Inflation (or deflation) which changes the buying power of money.
(b) The value given to possession of money now rather than later, since the former allows this amount of money to be invested for an interval of time to earn a real return (i.e. in addition to inflation). Alternatively, raising capital through a financial market implies the payment of a cost of capital for years to come (again independent of inflation). The annual factor that accounts for the time value of money independently of inflation is called the real discount rate (or real present worth rate).

The selection of such a rate is an important, sensitive and sometimes difficult matter (these points are discussed more fully in relation to generating system cost in Chapter 5):

– *Important* because it has to be known in order to compare two (or more) sums of money spent (or cashed) at different times.
– *Sensitive* because the economics of a project will depend very much on the selected value.
– *Difficult* if one finds that selecting the average cost of capital as the discount rate does not perfectly reflect the reality faced. This is understandable since, although selecting the average cost of capital is fine in theory, easy to handle, and used by a large number of utilities, the access to capital is not unlimited and a number of countries account for this by increasing the selected value for the discount rate (typical values for the real discount rate are 3–5% when only the cost of capital is considered, but these values may be twice as high if scarcity of capital is a major concern).

3.2.4. Reliability

In Section 3.1.2.2, the objective of electric system planning was stated as adequately meeting the demand for electrical power at the minimum cost. 'Adequately' meeting the demand can be interpreted in various ways with major implications for the generation planning effort. Typically, a technical constraint is used as the minimum acceptable level of generating system performance, or an economic criterion is introduced in an attempt to include the generating system reliability considerations directly in the determination of minimum cost.

The generation planner must design the future generating system to be responsive to such problems as:

- Random breakdowns of generating equipment (forced outages);
- Variations in demand to be met by the generating system (including random variations);
- Variations in hydraulic conditions which affect hydroelectric capacity and energy available to the generating system;
- Scheduled maintenance of generating equipment and refuelling of nuclear units;
- Changes in anticipated new capacity scheduled to come on line, e.g. delays or cancellations because of financial and other constraints.

It is thus necessary to consider explicitly what level of adequacy is required for system planning. As already indicated, overbuilding capacity will increase the average cost of generation because the costs of that excess capacity must be borne by the customers. On the other hand, underbuilding capacity will result in some portion of demand not being served. If the economic costs of this unserved energy are large and are added to the generation cost, this summed cost of generation also increases as the degree of underbuilding becomes more severe. Thus, theoretically at least, there may be an optimum level of reliability for the generating system depending on a large number of system characteristics.

Clearly, comparison of alternative expansion plans with greatly varying generating system reliability characteristics requires some method of accounting for the difference in expected quality of service. Historically, such differences were often ignored in thermal systems as long as the generating system met a minimal reserve margin (percentage of system generating capacity in excess of annual peak load), i.e. the lowest cost expansion plan that met the minimal value in all years was considered optimal. No credits were given for 'excess' reliability. The technical constraint has become more sophisticated in recent years, as measures such as loss-of-load probability (LOLP) and expected unserved energy have been used to set minimal performance levels (these measures and others are defined in Chapter 7). Generating system reliability is therefore often treated as a prespecified technical constraint in generation planning, thus avoiding the necessity of defining the economic effect of different levels of reliability. Presumably, the method used to specify the minimum acceptable reliability level accounted for the economic effects of not serving demand.

Another method of dealing with this difficult problem is to consider simultaneously the costs of additional generating capacity and the costs of not serving increasing levels of demand. Some current methods for expansion planning include a value of unserved energy in the cost function to be minimized over the planning horizon. Thus, rather than being used as a separate technical constraint, the optimum reliability level can be determined simultaneously with the optimum expansion plan. The difficulty often lies in deciding what value to place on unserved energy (this topic is covered in detail in Chapter 7). From the consumer's viewpoint, the cost of unserved demand is probably different from what it is from the utility's viewpoint, and this may differ from the cost from a national viewpoint.

Whatever the method of treating generating system reliability, an approach to comparisons of long-term expansion plans consistent in relation to reliability is necessary. Because various types of generating units have widely different characteristics that can significantly affect generating system reliability, the method chosen to represent reliability may have a major impact on the apparent optimal expansion plan obtained.

3.2.5. *Constraints*

The need for adequate planning in expanding electric power systems and the complexity of the problem are discussed in other chapters of this guidebook. We concentrate here on describing the factors which may present a constraint to the solution of the expansion problem and how these factors are treated. In the subsequent description the distribution system is neglected since its development usually covers a shorter period of time and has little influence on generation/transmission expansion.

In a general context, the solution of the expansion problem is the schedule of plant additions and network development over a certain period of time which yields the optimum benefits while satisfying the projected electricity demand with a certain margin of reserve and respecting certain foreseeable constraints. In other words, the expansion programme must include:

(a) The year-by-year capacity additions needed to satisfy the projected electricity demand with a satisfactory level of reliability with due regard to the characteristics of generating units in the existing system.
(b) The timely reinforcement of the transmission system so that the proposed network is capable of meeting power flow requirements under any foreseeable condition with due regard to load flows, power station siting, circuit and switchgear ratings, and transient stability limits.

To be an optimum, the proposed strategy (from (a) and (b) above) must lead to optimum benefits and, to be a realistic optimum, due consideration must be given to all aspects of the process which may represent a constraint (technical, manpower, financial, environmental, etc.) on implementing the programme. It is obvious that for the definition of benefits and constraints a wide range of aspects must be taken into account.

Definition of the benefits to be optimized is of paramount importance since it leads to selection of the economic criteria to be used for evaluating and comparing all alternative expansion policies for the power system. On the other hand, definition of the constraints is perhaps more complex since this requires the resolution of important issues, such as:

- Adequate reserve margins or level of reliability;
- Required quality of service in terms of continuity of supply, frequency and voltage;
- Availability of resources (manpower, fuel, funds);
- Technical considerations;
- Infrastructure needs;
- Environmental considerations;
- The country's policies concerning new units for electricity generation.

Some of these issues are quantifiable (at least approximately), permitting assessment of their effect on the solution of the problem. This is the case for the reserve margin criterion (e.g. in terms of a percentage of the load, largest unit connected to the system) and continuity of supply (e.g. a reliability criterion based on an acceptable value for the system's LOLP). Other concerns, such as the country's policies on new plants, may also be taken into account explicitly at the stage of establishing the types of units to be considered for expansion and, if necessary, some limits to the deployment programme for a certain type of power plant used as a candidate for system expansion.

All other issues, by their very nature, need a special analysis. This is usually done by separate techniques in order to represent the specific questions to be dealt with in each case. The various analyses are, however, highly interdependent.

This point can be illustrated for technical aspects by, for example, plant maintenance requirements, system stability, grid interaction with design, and performance of relatively large new power plants. Detailed analysis of each of these items would require that prior analysis of some other aspects has been already executed; for example, an adequate maintenance schedule for the power plants would need exact knowledge of the load characteristics and the plant mix over the maintenance period. For analysing system stability, various conditions for system operation must be considered, so that knowledge is required of load distribution, network configuration, and available capacities (disregarding any plant under maintenance). Each item, however, needs the application of special techniques commonly used for studying the operation and design of electric power systems and representation of the system in sufficient detail. In modern power system analysis these studies are performed with sophisticated computer techniques and use a system representation whose complexity depends on the problem being studied and the common practices of the country.

Another example of interdependence between the above items can be illustrated for the availability of resources (manpower, fuel, water, funds) to meet the requirements imposed by an expansion plan. This expansion plan may seem to be the optimum from the economic point of view but its implementation can be jeopardized by the manpower, fuel, cooling water and financial capabilities of the country, so that another solution to the expansion problem must be found if these constraints are to be met.

It follows then that simultaneous consideration of all factors affecting power system expansion analysis is a very difficult task. Representation of all constraints arising from these factors in a single computer model is practically impossible even in large modern computers. For long-term expansion planning of modern power systems a step-by-step procedure is normally applied, in which the planning exercise may be decomposed into two phases: the *economic optimization* phase and the *detailed analysis* phase.

Phase 1: The planner concentrates on the search for the most economical expansion plan, i.e. the programme of capacity additions and transmission system development that leads to an optimum value for the economic criteria selected for comparing alternative plans, while providing a satisfactory level of system reliability and continuity of supply and obeying other quantifiable constraints.

Any quantifiable constraints must be explicitly taken into account in finding this optimum. Due consideration may be given to remaining potential constraints in this phase by applying certain broad ground rules based on past experience in operating the power system or arising from qualitative considerations about the future conditions in which the system will operate.

It is obviously impractical to simultaneously compare the alternatives for generation system expansion and required development of the transmission system. Therefore, a number of system planners have adopted a decomposition method between generation and transmission planning consisting of:

(a) Determining the generation system expansion as a one-node exercise excluding network considerations and assuming that demand and generating facilities are concentrated at the same point;
(b) Deducing the corresponding optimal power plant siting and network expansion, with iterations being carried out between these two steps as required.

Such a decomposition approach is generally justified if the network is adequately interconnected, if the lead time for a transmission line is less than the lead time for a plant, and if the total investment costs for the transmission

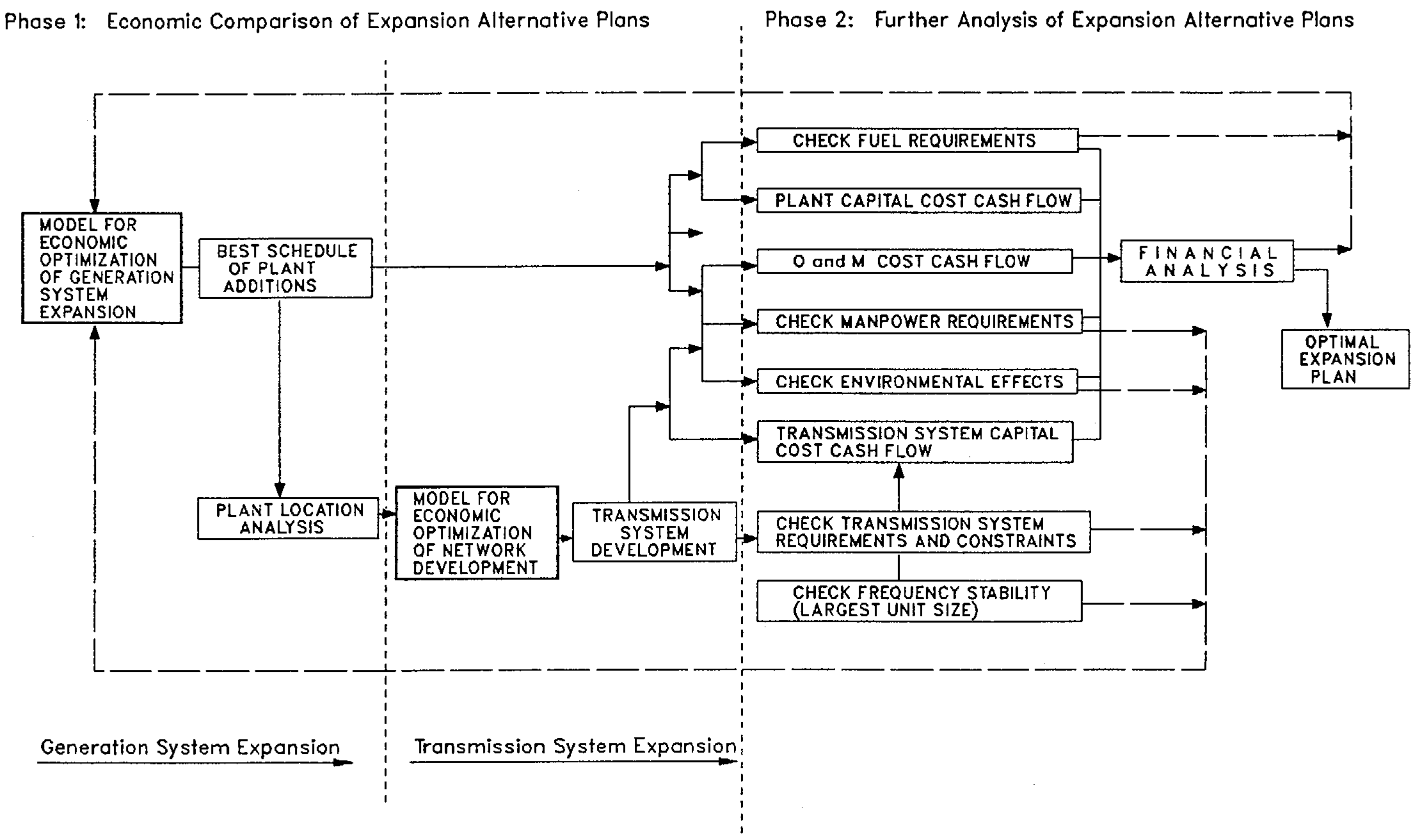

FIG. 3.3. Schematic representation of the planning process and consideration of constraints.

system are much smaller than those for the generation system. This is the approach followed by most models, such as WASP (Chapter 11).

As a first approximation, the transmission system is neglected, on the assumption that all generation expansion plans will lead to a similar development of the transmission network and only major differences in transmission requirements (e.g. long transmission lines to connect a power station to the grid, introduction of a higher grid voltage) are accounted for in the comparison of alternative system expansion plans. The best expansion policy for the generation system found by this method is then subject to analysis of the transmission network configuration. These studies evaluate load flows, transmission line requirements, voltage levels, system stability, etc., in order to determine the expansion required in the transmission system. Obviously, this expansion should also be determined by trying to minimize its costs. The results of the transmission expansion studies may also have a feedback effect on the assumptions made for determining the optimum schedule of plant additions.

Phase 2: Once the economic optimal solution for system expansion has been found, the planner must analyse the results and determine whether the economic optimum expansion plan is also a feasible programme from the standpoint of the system characteristics and the economic and financial situation of the region or country concerned. From this analysis the planner will check in more detail all potential constraints which were not explicitly taken into account in the previous phase. For example, the proposed system must be examined in order to guarantee frequency stability in the event of loss of the largest plant or unit when operating at full power. Fuel requirements imposed by the proposed plan have to be compared with the country's policy for energy use. Total manpower requirements of the plan should be determined and compared against the available resources of the country. Training requirements and the corresponding costs must be evaluated. A financial analysis of the proposed plan should also be made in order to assess viability of implementation and its impact on the overall economic development of the country. Certain solutions must be checked for relevant infrastructure needs (e.g. coal transport and new harbours) and environmental constraints. It is recommended that these checks be made not only on the economically optimal solution but also on some other near-optimal solutions, since the ranking between these solutions may be altered as a result of the analysis. Hence, adequate comparison between competing alternatives needs due consideration not only of all direct and indirect costs produced by each plan but also of its direct and indirect benefits. In some extreme cases, it may also be necessary to repeat Phase 1 to calculate new optimal solutions until the solution so found also satisfies all checks of Phase 2.

A simplified form of this procedure is shown in Fig.3.3. Selection of the appropriate technique for each phase of the expansion system analysis depends greatly on the complexity of the power system being studied and the technological, economic, social, etc., conditions of the 'environment' that will surround it.

It would be too ambitious to try to analyse all aspects of both phases of the expansion exercise in this section; the following description gives more emphasis to aspects of Phase 2. These can be broadly grouped into two categories, according to the type of check (or potential constraint):

(a) *Technical constraints*

(i) Transmission:
- short-circuit levels
- thermal ratings
- transient stability limits.

(ii) Limits to generating unit size:
- economic optimum and technical limit (frequency stability)
- load characteristics
- system reserve requirements
- maintenance requirements
- grid interactions with design and performance of new power plants.

(b) *Other constraints*

- Fuel requirements
- Manpower requirements and training
- Availability of funds
- Environmental impacts
- Infrastructure needs
- Miscellaneous.

These topics are treated in more detail in Chapter 9. The analytical techniques and computer codes available for the analysis of some of these problems are described in Appendix D.

3.3. CONCLUSION

This chapter has called attention to various aspects of electric system planning and to how long-term generation planning, which is the area mainly emphasized in this guidebook, relates to electric system planning. Although most of the remaining chapters are strictly geared to the long-term generation problem, the important considerations and constraints covered in this chapter must be kept in mind. It is recommended that a review of important factors, such as those shown in Fig.3.3, be carried out as part of every generating system planning study.

The next chapters cover concepts and analysis techniques which have been only briefly mentioned in this chapter and are important components of generation planning. Some models used for long-range studies of generating systems are briefly reviewed in Chapter 10, and the WASP model is presented in Chapter 11 as one example of a widely used optimization model for generating systems.

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Chapter 4

FORECASTING DEMAND FOR ELECTRICAL LOAD AND ENERGY

This chapter deals with techniques for predicting the demand for electrical energy, peak demand, and the hourly variations in demand patterns. It begins by discussing the importance of accurate load forecasts and the consequences of under- and overpredicting demand. Five principles of any good forecasting method are explained, followed by a review of three general types of forecasting methods which could be applied to either peak demand or energy forecasting. The chapter concludes with a discussion of techniques and issues specifically associated with forecasting peak loads.

4.1. THE VALUE OF ACCURATE FORECASTS

4.1.1. Forecasting needs of developing countries

In developed countries it is not uncommon to see a utility (government- or investor-owned) spend the equivalent of hundreds of thousands of US dollars annually in developing and updating load forecasts. To illustrate what is probably a representative level of effort, the five major utilities in the State of Wisconsin (with a combined installed capacity of 10 600 MW) spend roughly 1982 US $1 million per year on their forecasts of load growth. State agencies spend an additional US $100 000 making independent evaluations. These spending levels appear to be higher than what is budgeted for forecasting in many developing countries.

Some of the difference in forecasting expenditure can be explained by the supply-constrained nature of load growth in many developing countries. Systems still engaged in substantial rural electrification face excess demand for power, i.e. they are typically in a position to sell more power than they can generate. The utility essentially determines how much demand will grow by how much capacity it adds. The problem faced by the utility is how to maximize service with limited amounts of capital available for plant and equipment.

In addition, utilities in developing countries frequently follow a development plan which sets goals for economic activity and the domestic use of energy. In such circumstances, consumer demand is less relevant than the planned production goal. The utility's production goal may be formally or informally linked to an economic plan; it may also be tied into political and social objectives, such as reducing deforestation due to overharvesting of fuel wood, reducing rural migration to cities, or decreasing the balance of payments deficit from imported energy.

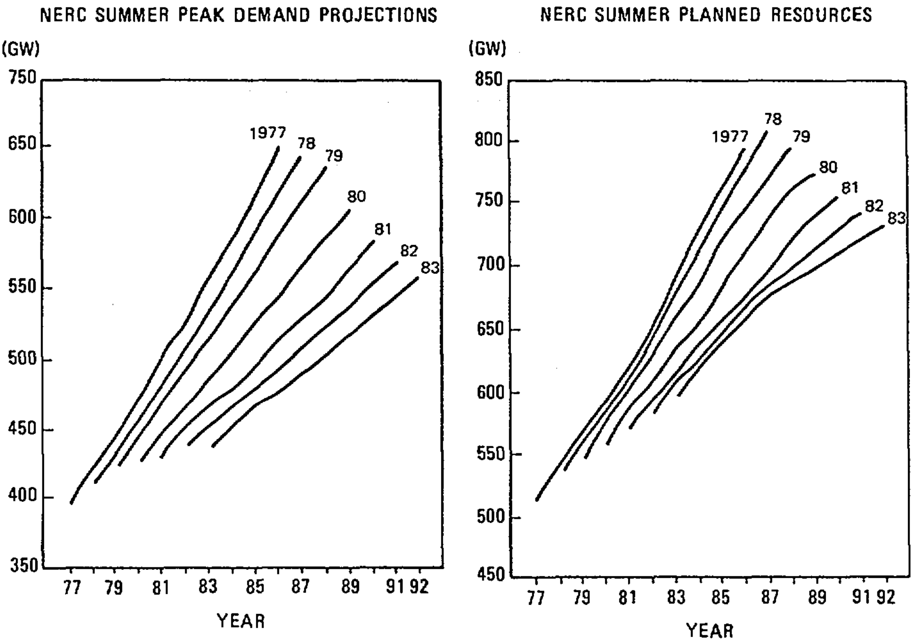

FIG.4.1. Comparison of National Electric Reliability Council (NERC) annual projections for summer peak demands and summer planned resources, USA (from [1]*):*

Ave. annual growth rate (%) projecting 10 years:	*Ave. annual growth rate (%) projecting 10 years:*
1977–5.7	*1977–5.0*
1978–5.2	*1978–4.6*
1979–4.7	*1979–4.3*
1980–4.0	*1980–3.7*
1981–3.4	*1981–3.1*
1982–3.0	*1982–2.7*
1983–2.8	*1983–2.2*

However, even where targets for total annual production are mandated to the utility, some study of loads is worth while. It is useful for the day-to-day operation of the utility as well as for long-term capacity expansion to understand why these changes are occurring.

4.1.2. The value of good load forecasts

How much is it worth to have an accurate idea of future electrical energy or demand requirements? The exact answer depends on the particular utility system in question. Many system managers and planners appear to undervalue forecast accuracy, i.e. they commit too few resources to this activity. The following discussion should indicate that the stakes are high and that, despite the speculation often surrounding load forecasting, it is worth making a serious effort to do it well.

Energy forecasts are wrong with embarrassing frequency. Figure 4.1 illustrates this by showing the aggregated 10-year forecasts of US utilities for 1977–1983 [1]. The 1986 summer peak load was forecast in 1977 to be approximately 650 000 MW(e). By 1983, the forecast 1986 summer peak load had fallen to approximately 475 000 MW(e). Forecast generating capacity for summer 1986 fell over the same period from nearly 800 000 MW(e) to 650 000 MW(e). That is a drop of nearly 150 000 MW(e) in expected capacity in just six years. Such large changes in expected demand and capacity over such short times make the generation planner's job especially difficult.

Demand growth in developing countries is often greater on a percentage basis than that shown in the latest US forecasts (Fig. 4.1). In addition, demand growth in some developing countries is limited by constraints in adding generating capacity. However, one implication of Fig. 4.1 relevant for all countries is that demand forecasts and associated capacity needs can change rapidly over relatively short periods.

Examples of inaccuracy in energy forecasts are so plentiful that one might despair of their value. If even well-endowed utility companies err so badly, what chance of success has a utility committing only modest resources to forecasting? One may well ask whether it is worth making any effort to formally forecast loads. Such a reaction is unwarranted. Thoughtful 'scientific' forecasts are almost always more accurate than naive extrapolations for the long-term planning horizon. Moreover, even if gains in short-term accuracy are small, the benefits from understanding load patterns can help in scheduling maintenance and planning the transmission and distribution system. Furthermore, a good knowledge of load pattern is essential for implementing load management schemes.

Three characteristics of utilities set them apart from most industries and heighten the negative consequences of inaccurate expansion plans:

- They commit relatively large amounts of capital for long periods,
- Comparatively long lead times are needed to add to their production capacity,
- They provide a critical input to the production processes of many other industries.

4.1.3. The cost of underbuilding

The cost of having insufficient electric generating capacity on hand to meet the customers' needs usually manifests itself quite visibly. Industrial facilities reduce production, commercial establishments have interrupted hours of service, households suffer inconvenience, goods may be damaged and people may be injured.

Depending on the number and duration of failures to meet load, customers may resort to any number of ways of protecting themselves from loss or inconvenience. These may be as direct as installing backup generating capacity or as subtle as avoiding storage of frozen foods. Such protective responses are also a cost to the economy since they divert resources (workers' time, capital) away from other preferred uses.

Persistent inability to supply loads can permanently idle productive capacity. Intermittent power blackouts and voltage reductions can also be costly. In recent years, system planners have begun to consider the economic worth of reliability as part of the system planning problem [2]. The value of reliability and estimated costs of not serving demand are presented in detail in Section 7.3.

4.1.4. The cost of overbuilding

The cost of building too much generating capacity is less apparent. From an engineering point of view, the system may be performing well, with few customer complaints about failures to meet their needs, and production targets may be met on schedule. From an economic point of view, this same system might be a failure. It might be consuming too many resources to provide a quality of service that the economy can ill afford.

How can one measure or place in perspective the cost of having more generating capacity than is needed to maintain a reasonable system reliability? One measure might be the annual carrying charge on the capital borrowed to build the excess plant and equipment. An analyst working for the World Bank found that a particular Brazilian system had reliability criteria which could not be justified by the economic consequences of moderately greater load losses [2, 3]. He estimated that an economically optimized system could save the equivalent of about 5% of the estimated total distribution system investment costs. Extrapolating these savings at half this rate of value, he estimated that the net potential savings on total electric power sector investments for developing countries alone would be over US $\$1 \times 10^9$ per year (in constant 1979 dollars) during the next decade.

Perhaps a more tangible way of looking at the cost of overbuilding is to ask what other productive uses the capital could have been put to. For example, the cost of new generating capacity must be compared with the cost of tractors and fertilizer for agriculture. Thus, the tangible cost of the generating capacity could be the food that might otherwise be produced. Thinking of the alternative uses and consequent benefits of capital is a way to keep electric utility planning in its proper context.

4.1.5. Balancing the costs

Decision-makers at an electric utility are confronted with formidable costs from either overbuilding or underbuilding generating capacity. They also know that load forecasts can be an unreliable indication of future needs.

In the face of these costs, decision-makers have two options: to improve the accuracy of the forecasts or to reduce the costs of an incorrect forecast. The remainder of this section deals more carefully with the first option. It is worth pointing out first, however, that the adverse consequences of an expansion plan that is too fast or too slow can be mitigated by putting more flexibility into the construction schedule. Flexibility can be achieved by modifying the terms of the construction contract to allow for lower penalties for schedule modifications. Such 'escape clauses' in a contract usually increase the bids of contractors but may still be more economic if load growth is highly uncertain. Another approach is to build smaller units, perhaps in a modular fashion. This, of course, militates against some technologies, such as nuclear and conventional coal boilers, and may add to the cost per installed kW. Nonetheless, the value of flexibility in the construction schedule should not be overlooked if uncertainty of demand is an issue.

4.2. PRINCIPLES OF FORECASTING

A few principles should be followed in all good forecasting methodologies. By following them, the forecasting process can provide the planner with more accurate and more useful information. These principles will also make it easier for the upper management of the organization to accept and act upon the work of the forecaster.

4.2.1. Identify causality

For a time it was all too common for forecasters to use correlations of demand with time to establish growth trends. However, time trends should be regarded as the last resort for forecasting and should only be used for short-term forecasts, i.e. a few years ahead at most.

The good forecaster is concerned with causes. The search for cause and effect relationships distinguishes the scientific approach from mechanistic reliance on historical correlations.

The basic reasons for changing demand are easy to identify. Economic activity creates commercial and industrial demand. The number of households connected to the grid and their access to electrical appliances shape domestic demand. Beyond this level of generality the search for causal relationships can take many forms, depending on the characteristics of the utility system in question.

By specifying why a change in demand is occurring, in terms that non-planners can relate to, the forecaster increases the likelihood that the forecast will actually be used as the basis for decision-making, rather than merely a ritual that must be performed before upper management exercise their own intuition about the future.

4.2.2. Be reproducible

This principle refers to the 'objectivity' of the forecasting process. A forecast is reproducible, and therefore objective, to the extent that another person can understand and recreate the process by which it was derived.

Mathematical representations often improve the reproducibility of a forecasting method, although to be reproducible a methodology need not be specified with mathematical precision (in a series of equations and definitions), but a clear and unambiguous set of instructions is required on how the forecast was derived. An example of a simple but reproducible forecast might be: "Domestic energy use, defined to be metered demand in the XYZ tariff class, was forecast to grow in direct proportion to the number of domestic customers officially connected to the grid." This statement clearly specifies the basis of the forecast.

4.2.3. Be functional

The forecast should be constructed so that it fits the decision at hand. For example, if the decision concerns the scheduling of maintenance for existing plants, the forecast horizon should be one year, divided into monthly (perhaps weekly) increments. If, on the other hand, the decision relates to the construction of a central generating station, the forecast should focus on annual increments of demand for at least the lead time for constructing the plant (and probably for a decade or more beyond that). In both short- and long-term planning, the pattern of daily variations in loads must be considered. In long-term planning, the potential for major changes in how electricity is used by time of day and season of the year is greater, and must be explicitly analysed.

4.2.4. Test sensitivity

Simple or complex, most forecasting methodologies are driven by key assumptions about the future, e.g. birth rates, household formations, migration, new business development, war/peace, and weather. The forecaster, with a healthy appreciation of uncertainty, will attempt to convey the impact of this uncertainty on the forecast. One significant way to do this is to prepare alternative forecasts, often called *scenarios,* which contain differing assumptions about important variables shaping the forecast.

If the forecast methodology is a formal mathematical model, the scenarios can be built round alternative values of independent variables in the equations, for example high and low gross domestic product (GDP) growth. This is relatively well suited to econometric and end-use models, which usually contain a number of independent variables linked to demographic, economic and technological events. With less reproducible methods, particularly those that are highly subjective, scenarios are more difficult to define. By its nature, a subjective judgement of the future is less amenable to assigning probabilities or ranges than is a formal model. Nonetheless, it is still appropriate for the judgemental forecaster to give some indication of the upper and lower bounds of demand.

4.2.5. Maintain simplicity

Modelling is specifying clearly and unambiguously the relationships that govern a physical or social activity. Most real-world activities are more complex than we could describe in a model or would need to. The principle of simplicity dictates that we include only as much information in the model as is necessary for accurate prediction. In the practical affairs of developing a utility system plan, simplicity is a necessity. A simple method consumes less resources (time, money) in its development and is easier to understand when completed. Of course, improving functional uses or accuracy often make the method more detailed and/or analytically sophisticated. The planner is then forced to balance the advantages of simplicity with other principles of good forecasting. Before complicating a forecast, the planner should be sure that it serves some definite purpose and is not just a concession to theoretical or mathematical elegance.

4.3. ALTERNATIVE FORECASTING TECHNIQUES

Specific guidance on model building or selection is difficult for two reasons: expert modellers disagree on the technical merits of alternative approaches, and different tasks require different tools. Therefore, this section reviews alternative approaches to modelling and discusses the strengths and weaknesses of each approach.

In most cases the choice of a method will depend more on the background and time available from the planning staff than on the technical merits of the method. For this reason, this section stresses the importance of identifying the data, computational and staff resources associated with each method presented.

There are numerous techniques for modelling and forecasting electrical energy and load requirements. Each analyst and organization is apt to characterize its technique in a different way. The following scheme of classifying models emphasizes the different ways in which analytical techniques treat customer choice and behaviour. Models are divided into: *time series, econometric* and *end-use* methods. These techniques are also useful for forecasting overall energy demand, as briefly discussed in Chapter 2.

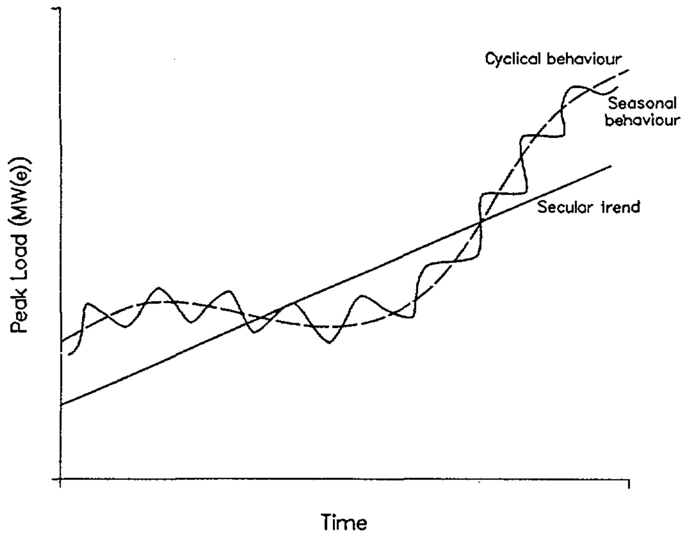

FIG.4.2. Illustration of three systematic variations in time series data.

4.3.1. Time series

Searching for systematic and recurrent relationships between loads at various points in time is the essence of time series modelling. Since time is the only explanatory variable, the data collection requirements of this technique are the least of any forecasting technique. However, not all time series models are easy to implement. A time series model, using Box-Jenkins [4] analysis to estimate hourly loads, requires thousands of data points on loads[1], uses a complex computational algorithm to estimate the structure of the relationship, and requires the use of a rather powerful computer[2]. At the other extreme are simple annual time trends that can be estimated with a straight edge and graph paper.

The predictive accuracy of time series analysis varies tremendously from application to application. For short-term forecasts of relatively large and stable systems, it can be as accurate as more elaborate models. It is subject to extreme errors in the 10–20 year horizon required for capacity expansion planning.

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[1] As a general rule, one needs data on 6–8 years of monthly or quarterly data to use a Box-Jenkins model.

[2] Commonly available software packages that can perform Box-Jenkins analysis (TSP, SPSS, MINITAB) require between 300K and 500K of accessible memory.

Time series analysis can be distinguished from trend analysis in that the former seeks to decompose the data into at least three 'systematic' components (illustrated in Fig.4.2):

(1) *Seasonal variation:* A pattern that repeats itself in some similar fashion between different periods of the year, e.g. high pumping loads associated with irrigation in the summer months.
(2) *Cyclical variation:* A pattern that repeats itself over many years, generally with a similar frequency and amplitude; for example, 5–7 year business cycles affecting overall GDP growth have been shown to occur in many economies.
(3) *Trend:* Any relatively consistent rate of change from year to year that remains after the above two components are filtered out.

Random variations obscure these systematic components in time series data. Since they show no regular patterns, they cannot be used for predictions.

By being sensitive to these components, the analyst can develop a reasonably predictive model with a minimum of effort. Guidelines for applying time series models to electric utility load forecasting are:

(1) Avoid using monthly or quarterly data to indicate annual trends without first 'deseasonalizing' the data. (More about this in Section 4.4.)
(2) Be cautious in using time series on systems where sporadic changes from period to period are very large relative to the average historic load. For example, a small 700 MW system, in which a recent industrial plant opening increased the overall system load by 50 MW in one year, will produce misleading trends.
(3) Consider adjusting the data for truly extraordinary events that shock the system off its long-term trends, e.g. wars, general strikes, natural disasters, extreme weather conditions.
(4) Watch for significant social or economic events that would cause 'turning points' in long-term trends (for example the 'oil price shock' of 1973–74 changed energy demand world wide). The data prior to significant turning points should be either discarded or less heavily weighted.

This last point brings up the most critical weakness of all models that use historical relationships to predict the future. Such techniques cannot predict structural changes that alter the way in which decisions on energy use are made, either by individuals in markets or by central planners. An analyst whose data show the most recent few years to be above or below a longer term trend is forced to make a judgement on whether this represents a turning point and thereby establishes a new trend or is merely a passing aberration. History is replete with forecasters of every type who have missed turning points.

One way in which the analyst exercises his other judgement on the occurrence of turning points (often without knowing it is happening) is through the selection and weighting of the sample. Those who believe that the restructuring of oil prices in 1973 represented a turning point in demand will weigh less heavily, or discard, data points before that year. Selecting the time span to be used as the basis for a time series trend is critical to (one might even say it determines) the projected values. An analyst can easily generate 20-year forecasts that differ by a factor of two simply by varying the historic sample period over which the trend is estimated by only a few years. The ease with which the results can be thus manipulated should illustrate the arbitrary nature of simple linear or log-linear trends. More sophisticated time series techniques, such as Box-Jenkins analysis, can make judgements in predicting changes in time trends more explicit and, to a certain extent, less arbitrary.

An example of the use of time series for long-term forecasting of loads for the Wisconsin Electric Co. (USA) is described in Ref. [5][3]. The first step was to separate, with regression analysis, daily summer peak demands (1964–1977) into two components: a base demand and a weather-sensitive demand. The base component of monthly peak demands was modelled using a Box-Jenkins model with Box-Tiao intervention techniques. The model consisted of three structural components: (a) the overall trend in monthly peak demands from 1964 to 1977; (b) an intervention in Dec. 1973 related to the 'energy crisis'; and (c) an intervention related to the economic downturn experienced from late 1974 to late 1975.

The second intervention was treated in two different ways. The first method used a one-period downward-level change presumed to influence the data series beginning in Nov. 1975. This assumption indicates that there was a sudden impact with no lasting effect on the expected annual growth rate. The second method assumed that the event had an effect on the growth rate itself as well as the temporary impact. The second method had the effect of reducing forecast growth significantly over long time horizons. The conclusion drawn from the work was that these techniques, coupled with the econometric techniques also being used, provided reasonable results required to comply with a directive from the State regulatory agency.

4.3.2. Econometric models

This class of model, like the time series model, uses historical regularities to predict the future but attempts to go beyond time series models in explaining the *causes* of trends. Econometric models postulate explicit causal relationships between the dependent variable (either energy demand or loads) and other economic, technological or demographic variables. Simple univariate models which use the relationship between energy growth and GDP are in a sense causal since they postulate, at least implicitly, that economic activity creates the need for electricity. Other causal energy models can be more refined and detailed in the

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[3] Especially Section 6 by R. Kalscheur and its appendix by G.C. Tiao.

way they attempt to explain this link between economic activity and the demand for electricity. They may, for example, break down economic activity by specific classes of industry and commerce, and relate each separately to the demand for electricity.

In general, an econometric model would have the form:

$$D_{i,t} = a + \sum_{j} b_{i,j} X_{i,j,t} \tag{4.1}$$

where

$D_{i,t}$ is the energy demand in sector i at time period t,
a is a constant,
$b_{i,j}$ is the coefficient to be determined for sector i and explanatory variable j,
$X_{i,j,t}$ is the level of activity for explanatory variable j, such as output level, the price of a fuel, the prices of competing fuels, and weather variables.

Other things being equal, econometric modelling would be preferred to time series analysis. Even if both techniques could predict changes in demand with equal accuracy, the econometric model would be more valuable since it might help in understanding why changes in demand were occurring. Knowing causes can help to plan to meet future needs. For example, if the econometric model revealed how responsive demand was to changes in the price of electricity, this could be used to predict the effects on demand and on revenues received of changes in electricity prices.

Unfortunately, causality does not easily reveal itself to the modeller, even under the best of conditions. The statistical estimates derived from deterministic models, especially for developing countries, are often hopelessly implausible. These poor results can be attributed to insufficient data, errors in data, or a mis-specification of the model in the first place. Statistical models do not indicate causal relationships; they merely help to quantify the parameters of relationships postulated to exist by the modeller. Thus, the modeller must bring considerable insight (guesswork?) to bear on the problem of specifying the model; i.e. the modeller must identify the explanatory variables and the functional form by which they are related to energy demand. The simple linear econometric model shown above is easy to estimate but will probably not produce very accurate forecasts. More complex (multiple equation, non-linear and dynamic) models are theoretically preferable and generally produce more accurate coefficient estimates.

Numerical data are an essential part of applied econometrics. The models depend upon extensive historical data to estimate relationships. Thus, the modeller must be familiar with sources of data and their accuracy. Often data are unavailable on a variable thought to be causally linked to demand (say physical output from factories); so the modeller might use instead a surrogate variable (such as the value of shipments). This can add a further degree of ambiguity and inaccuracy to the model.

Problems related to availability and accuracy of data represent only one barrier to the use of deterministic models, which frequently require a significant degree of training in the branch of statistics that deals with regression analysis. Although trivial models can be estimated by novices, more sophisticated, and presumably more accurate, models require considerable staff training and specialized algorithms for estimating the models, e.g. two-stage least squares or maximum likelihood estimators. (These algorithms are available in many 'user friendly' software packages, such as TSP, SPSS, SAS, MINITAB or BIOMED.)

Aggregate econometric models can be used to forecast total electrical loads or sectoral loads, i.e. residential, commercial, industrial and agricultural. If the sectoral approach is used, the explanatory variables can be expected to vary between sectors.

An example of a model with electrical consumption as the dependent variable is shown below [6]. The vector of independent variables indicates the types of variables that may be included in the specification:

$$D_{i,t} = f(N, I, PE, PC, D_{i,t-1}, CD, WV, S) \tag{4.2}$$

where

$D_{i,t}$	is the electricity demand in year t for sector i,
N	is the number of customers in the sector or other measures of the volume of activity,
I	is income,
PE	is the price of electricity,
PC	is the price of competing fuels,
$D_{i,t-1}$	is the electricity demand in sector i for year t-1,
CD	is the conservation dummy,
WV	is the vector of weather variables,
S	is the vector of saturations of major electricity-using appliances.

This method of forecasting has been widely applied in recent years [7–12]. As a specific example, the following equation was used prior to 1980 by the Wisconsin Electric Co. to analyse residential electrical consumption [7]:

$$D_t = 1.136 + 0.872\,D_{t-1} - 0.341\,P + 0.021\,W + 0.115\,I \tag{4.3}$$

where

D_t is the MW·h consumption per residential customer in time period t,
D_{t-1} is the MW·h consumption per residential customer in time period t-1,

P is the residential block weighted price of electricity,
W is the temperature-humidity index,
I is the total per capita income.

The intuitive relationships indicated in Eq. (4.3) appear to be in the right direction; for example, if the price of electricity increases, demand will fall off somewhat, assuming everything else remains the same. An alternative equation was also developed in which the saturation of residential customers with central or room air conditioners and the saturation of residential customers with electric heating were introduced as explanatory variables and the demand from the previous period (D_{t-1}) was dropped. Similar equations were estimated for manufacturing value added in large industries in Wisconsin, employment, wage rates, electricity consumption in large industries, electricity consumption in other industries, commercial electricity consumption, and quarterly peak demand (MW).

4.3.3. End-use models

This final class of model is more diverse than the preceding types. In one form or another, end-use modelling is probably part of most utility forecasting methods. Its distinguishing characteristic is a detailed description of how energy is used. Such models usually begin by specifying reasonably homogeneous uses for which energy is ultimately required, such as heating water, cooling buildings and cooking food. The model then describes, via mathematical equations and accounting identities, the types of energy-using equipment that businesses and households have, and how much energy is used by each type of equipment to satisfy the predetermined levels of end-use energy demanded. By summing up the units of equipment times the average energy used by each class of equipment, total energy demand by fuel type is revealed. The content and uses of end-use models in an overall energy perspective are described more fully in Sections 2.2 and 2.3.

Simply multiplying types of equipment by average use values is nothing more than an accounting framework – a trivial form of modelling. Even so, this type of framework can generate insights into the way energy is used and how it might change in the future.

Optimization models are a step beyond accounting models. By specifying an objective function (such as minimizing cost) and identifying both the unit costs of using energy in the given processes and the constraints to the system, the accounting model can be transformed into a device that will predict how customers will act (assuming that their objective function is properly specified), given the assumptions about cost/constraints. End-use models are often linked to econometric models.

The data requirements grow linearly and the computational difficulty grows exponentially with the descriptive detail sought by the modeller. Optimization models not only require information on the conversion efficiencies of energy-using technologies, they also require cost data. While the computational requirements of end-use accounting can be satisfied with minimal computer time, optimization of realistic energy models requires significantly more computing capabilities.

Optimization models are used heavily for business and government planning in both market and centrally planned economies. In a market economy, modellers insert market-determined prices for unit costs, while, in a planned economy, they may use government-determined values. Optimization models are particularly useful for centrally planned economies. Where a central plan defines industrial output targets and housing needs in detail, it would be counterproductive if the utility system's expansion plan was not consistent with these goals. A mathematical model is the only practical way to keep track of all these interactions and explore the consequences of a failure of any sector to meet its production target.

End-use models are often weakest in predicting consumers' fuel-use decisions.[4] With the available data, they can easily describe where the energy is being used and for what purposes but, without a theory to explain choices, they are limited in their explanatory power to predict the future. The ideal end-use model (rarely achieved) would, for example, not only tell us the average watts of lighting energy in households, and how this amount has changed over time, but also what caused households and/or housing operators to make these changes.

The MAED model (Model for Analysis of the Energy Demand) is a simulation model designed by the IAEA to evaluate medium- and long-term demand for energy in a country or a region (Appendix A). An example of energy demand studies conducted by the IAEA by means of this model is described in Section 2.3.1.

End-use models have also been applied to numerous energy demand studies in recent years (see e.g. Refs [7, 8, 13]). This type of model offers the advantage that it is generally sensitive to detailed technology and policy changes (e.g. the effect of more efficient refrigerators) at the expense of being data-intensive. An additional complication in some end-use approaches is the identification of a consistent overall set of socio-economic and technical assumptions, e.g. how to model the expectation that efficiency of new appliances would increase more rapidly if electricity prices increase from some reference level.

Table 4.I summarizes the attributes of the three basic forecasting methods discussed here. Because models differ so greatly with each of these categories, these general attributes may not apply in specific cases. They do, however, point to what one can expect from the majority of these techniques.

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[4] Although, in general, the same is true for most types of model described in this chapter, some econometric models have cross-elasticities that attempt to account for fuel substitution decisions.

TABLE 4.I. GENERAL CHARACTERIZATION OF FORECASTING METHODS

Characteristics	Time series	Econometric	End-use
Best forecast horizon	Months to a few years	1 to 10 years	10 to 30 years
Data requirements	Minimal energy/load data only	8 to 12 year time series for several independent variables	Proportional to desired detail of model
Computer requirements	Trivial for trend models; significant for complex models	Moderate – many models can be run on microcomputers	Most models can be run on micro-computers
Specialized skills	Trivial for trend models; significant for complex models	Relatively easy to build models – experience and training needed to detect/solve problems	No specialized training except for optimization models
Suitability for analysis of system shocks/scenarios	Poor	Good for variables explicitly in model	Generally the best method of all

4.4. LOAD FORECASTING

The maximum instantaneous load within a given utility service territory is called its peak demand. In electric systems with predominantly thermal capacity, it is more important to know the peak demand than to know the amount of electrical energy demanded, since the peak demand often sets the capacity expansion goal. For systems with large amounts of hydroelectric capacity, it may be more important to know energy demand because these systems may have energy limitations. Knowledge of the peak demand is also important for planning the type of generating capacity that should be built, when it should be scheduled for maintenance, and how much reserve will be needed (both spinning and standby). Since customer characteristics vary throughout the area served by the utility, each distribution substation may experience its peak demand at a different time of day. The system peak is usually defined as the coincident peak of all substations in the entire utility service territory.

Most of the time, it will be easier to model energy use than peak use. Given an energy forecast, the simplest way to obtain a peak load forecast is to compute it, using the simple identity:

$$\text{Peak load} = \frac{\text{Energy}}{\text{Load factor} \times \text{period of time}} \tag{4.4}$$

where load factor is defined as the ratio of average demand to peak demand for the period of time considered. Utilities employing some variant of this technique usually forecast the load factor judgementally or by extrapolating its trend.

While this method is quite easy to implement, it is subject to severe 'turning point' errors if fundamental changes occur in the load factor. These can be caused by such things as a rapid increase in the use of air conditioning or a rapid growth in a certain type of economic activity, such as hotels supporting a tourist industry, with a high demand at a particular time of the day.

Taking the simple load factor identity one step further, one can estimate the statistical relationship between peak demand and energy over some recent historical time period and use the resulting equation to forecast peak loads. When a significant portion of the load is weather-sensitive, usually because of a high level of space conditioning in residential and commercial buildings, the above model can be improved by regressing peak demand against base energy, plus a weather variable:

$$\text{Peak load} = a + b \times \text{base energy} + \text{weather} \tag{4.5}$$

where base energy is the non-weather-sensitive portion of the load[5] and weather is some index of meteorological conditions known to be correlated with space conditioning loads.

Such models can be prepared for various seasons of the year to measure the peak-to-energy relationship more accurately. Typically this is done by separating the sample into rainy and dry seasons, winter and summer seasons, or monthly periods. The smaller the time intervals, the more useful is the forecast for scheduling maintenance.

Another approach to peak load forecasting is to use a time series analysis. This analyses variations in peak demand in isolation from energy use. Two approaches to time series analysis are suggested here: one is a simple arithmetical decomposition of a time series and the second is a statistical model.

A time series can be thought of as containing three components: trend, seasonal and random. First, the seasonal component is broken out by taking the ratio of a monthly or quarterly data point to a moving average of all periods for

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[5] Usually obtained by subtracting from total energy the estimated use of energy for space conditioning or by using total electrical energy demand during the months of the year when weather is not a factor influencing demand.

TABLE 4.II. SAMPLE MONTHLY LOAD DATA

	(a) Monthly observation (MW)	(b) Moving ave. of last 24 months (MW)	(c) Ratio of (a)/(b)	Monthly data with seasonal effects removed ((a)/(c)) (MW)
Jan.	2300	2000	1.15	2000
Feb.	1900	1996	0.95	2000
Mar.	1850	1990	0.93	1989
Apr.	1840	1984	0.93	1978
May	1890	1980	0.95	1989
June	1920	1978	0.97	1979
July	1905	1974	0.96	1984
Aug.	2010	1976	1.02	1971
Sep.	1910	1973	0.97	1969
Oct.	1855	1968	0.94	1973
Nov.	1890	1965	0.96	1969
Dec.	2100	1971	1.06	1981

the last two to three years. Suppose, for example, one observed the monthly load data displayed in Table 4.II. The seasonal adjustment factors in column (c) may themselves show a trend from year to year and might be extrapolated according to their own trend in developing the forecast. For example, if the seasonal adjustments for the month typically containing the system peak were 1.10, 1.13, 1.18 and 1.21 for the last four years, an upward trend in that month's contribution to peak would be indicated.

After removing the effects of seasons from the data, the analyst can look for a trend, which is a systematic change in the level of the time series. The trend might be determined simply by plotting the observations with seasonal effects removed and looking for a pattern, or by running a series of regression fits of the data using alternative specifications of the model. After the trend has been determined, it can be extrapolated for any number of periods into the future. The trend value should then be readjusted for seasonal effects to produce the actual predicted value for that future period.

This technique is more appropriately described as fitting rather than modelling a time series. *Fitting* only seeks a formula for reproducing a given series of values;

modelling seeks to understand why certain changes occurred in the trends at particular points (interventions) or why the pattern of monthly variation changed. This is a general class of time series models that use various combinations of autoregressive terms and moving averages, thereby enabling the analyst to bring more reasoned judgement to bear in selecting the functional form of the model. The best example of such a technique is the Box-Jenkins analysis, which isolates all the time series components discussed above as well as structural changes in the time series called interventions, as discussed in Section 4.3.1 above. These time series components are then used to project the time series into future periods. Historical data obviously cannot incorporate changes in the future which are unexpected or which differ significantly from the past. However, if some fundamental structural change occurred in the historical series, its effect must be modelled in order to isolate the previous trend from the fundamental change. The use of the intervention or structural change components requires judgement by the modeller as to whether the shift is of a long-term (permanent) or short-term (temporary) nature.

4.5. LOAD DURATION

Now let us suppose that the analyst has carefully prepared a forecast of total energy demand and peak demand for a given future period. To use a typical expansion planning model, one must specify further information about the nature of electricity use. It is necessary to have a description of how many hours of a given period loads will have at a given value. One common way is to use load duration curves.

A load duration curve shows the cumulative frequency distribution of system loads. It represents graphically how much energy is supplied to various levels of system load (Fig. 4.3). System load is shown in MW on the vertical axis and in hours during which that load was exceeded on the horizontal axis. The shape of the load duration curve will directly affect the mix and operation of generating capacity. As the peak is reduced, the need in predominantly thermal systems for less efficient turbine peaking units decreases and, as a result, oil and/or gas consumption decreases. As the load duration curve flattens out, better use can be made of efficient baseload thermal plants.

It should be stressed that load factor alone is only a crude measurement of load characteristics. The distribution of loads, as shown by the load duration curve, gives the planner vital information for determining the proper mix of base, intermediate and peaking capacity. It also helps to determine the cost of failing to meet loads on demand.

To project load demand characteristics for future years, a simple technique is to use the latest known normalized seasonal load duration curves and to weight the curves by the projected peak load for each corresponding period. This assumes

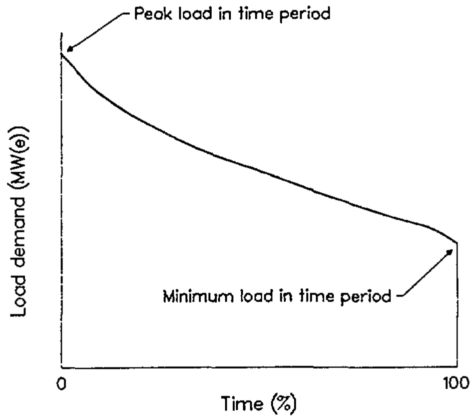

FIG.4.3. Load duration curve.

that electricity use characteristics will not change within a season and that load growth is distributed consistently over all types of demand.

If the load demand characteristics change, the above method will not reflect these changes. In typical practice the analyst often adds or subtracts from the shape of the load curve in some arbitrary fashion to make total energy (the area under the load duration curve) correspond to the energy forecast. The shape of the load duration curve has a strong bearing on the selection of capacity and the cost of the system. Arbitrary adjustments (those chosen without a specific reason) will therefore lead to equally arbitrary expansion plans.

A less arbitrary way of modifying the curve is to use reasoning similar to that used to project loads. First, fit an appropriate mathematical function to load curves for a number of historical periods (say the last 5–10 years). Next, note the trends, if any, in the parameters of the model. Finally, extrapolate the trend in the parameters and recompute the curve. New load duration curves can then be computed from these projected load curves.

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Chapter 5

REVIEW OF ECONOMIC CONCEPTS

5.1. BASIC CONCEPTS OF ENGINEERING ECONOMICS

Engineering economics is the study and comparison of alternative courses of action with respect to their costs. It encompasses the principles, concepts and techniques required for making economic decisions about competing alternatives. These principles and techniques play an important role in electric power system expansion studies that require analysing and making economic decisions about alternative technologies for long-term planning horizons.

This section briefly reviews a number of the basic engineering economics concepts and tools applied in other chapters of this guidebook. Included are discussions of the time value of money, interest formulas, escalation and inflation, discounting, present worth and annual equivalent cost analysis, and depreciation. A number of simplified examples are presented to illustrate the basic concepts. More complete descriptions of these concepts can be found in the traditional textbooks on engineering economics and other documents listed in the Bibliography at the end of the chapter.

5.1.1. Time value of money

An understanding of the basic principles of engineering economics requires an understanding of both the time value of money and the techniques that can be used for equating sums of money that occur at different points in time. When two sums of money occur at the same point in time, a direct comparison is possible. However, when they occur at different points in time, direct comparisons are usually not possible without first accounting for the change in value that occurs over time. This change in value occurs for two basic reasons: (1) economic forces, such as inflation or deflation, change the buying power of money, and (2) money can be invested for intervals of time to earn a real return (i.e. independent of inflation or deflation). Therefore, before any cost or benefit comparisons can be made involving monetary amounts which occur at different times, all monetary values must be equated to a common point in time (i.e. all cash flows must be put on a time-equivalent basis).

This fundamental concept of the time value of money can be illustrated by comparing two sums of money[1]: \$100 today and \$100 a year from now. The \$100 today is worth more than the \$100 a year from now if the money can be invested in some fashion so as to produce a *return on investment* (e.g. interest paid by a bank on money deposited in a savings account). The term *interest* generally

[1] For convenience, all examples in this chapter are in US dollars.

refers to the return earned by the productive investment of capital. The *interest rate* is defined as the ratio between interest chargeable (or payable) at the end of a period of time to the money owed (or invested) at the beginning of the period. If $100 is invested in a savings account at an annual interest rate of 10%, for example, it would be worth $110 at the end of one year. In theory, therefore, having $100 today or $110 a year from now is a matter of indifference to the investor, unless a better investment opportunity were available. Conversely, $100 one year in the future is worth only $90.91 today assuming an annual interest rate of 10%.

The mathematical process by which different monetary amounts are moved either forward or backward in time to a common point in time is called *present value* or *present worth* analysis. Other commonly used terms denoting the process of converting monetary values to an equivalent amount at a different time include *compounding*, which corresponds to the process of moving money forward in time, and *discounting*, which corresponds to the process of moving money backward in time. These basic economic concepts are discussed more fully below.

5.1.2. Interest formulas

The interest formulas presented in this section are based on discrete time periods and on a discrete interest/discount rate. Although a one year interest period is used in the illustrations, the formulas presented apply to interest periods of any length.

Six basic time/money relationships, or interest formulas, that are useful in determining equivalent values for sums of money occurring at different times are summarized in this section. The following notation is used in developing the formulas:

- i is an interest or discount rate per interest or discounting period[2],
- N is the number of interest or discounting periods,
- P is a present sum of money,
- F is a future sum of money at the end of N periods,
- A is an end-of-period payment (or receipt) in a uniform series of payments (or receipts) over N periods at i interest or discount rate.

5.1.2.1. Single compound amount formula

If P dollars are deposited in an account in which interest is accumulated at a specific rate i for a given number of periods N, then the account will grow to

[2] In accordance with traditional derivations, a single symbol for the rate of interest or discount is used in the development of the six formulas. However, in order to differentiate explicitly between the interest and discount rate, a different symbol (e.g. the letter d) could be substituted for the letter i in the development of the single present worth formula.

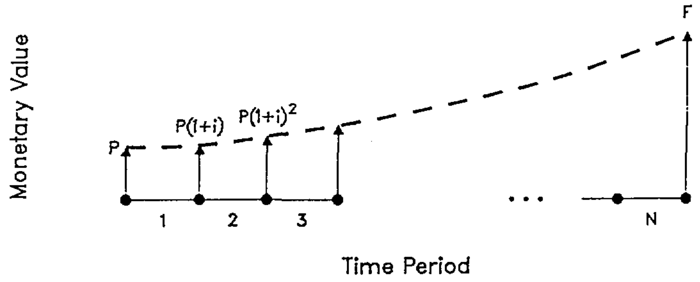

FIG.5.1. Cash flow diagram for present and future sums.

$P(1+i)$ by the end of the first period and to $P(1+i)(1+i)$ by the end of the second period (Fig.5.1). In general, at the end of N periods

$$F = P(1+i)^N \tag{5.1}$$

The expression $(1+i)^N$, denoted $(F/P)^i_N$, is called the *single payment compound amount factor.* This expression is the basis of present worth arithmetic and is used to calculate the time equivalent of money at a different point in time. Equation (5.1) is used whenever a monetary amount is moved forward in time.

Economic studies are occasionally performed using continuous compounding rather than discrete interest rates. In this case, the compound amount factor $(1+i)^N$ becomes e^{qN}, where q is defined as the continuous rate of interest (i.e. it is assumed that interest is computed and added to principal at every moment throughout the period). To establish an equivalence between the discrete rate of interest/discount i and the continuous rate of interest/discount q, consider a year divided into k time periods of length 1/k. In the limit when the interest periods are made infinitesimally small, $i = e^q - 1$. Therefore, when $i = e^q - 1$, the formulas $F = Pe^{qN}$ and $F = P(1+i)^N$ give identical results. Similarly, the expression $e^q - 1$ can be substituted for i in the other discrete formulas presented in this section to develop continuous compounding formulas.

5.1.2.2. Single present worth formula

The present worth P of a sum N periods in the future, F, can be determined by rearranging Eq.(5.1), the single compound amount formula, to express P in terms of F:

$$P = \left[F \frac{1}{(1+i)^N}\right] \tag{5.2}$$

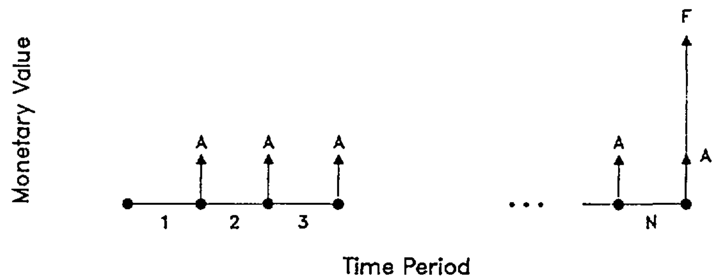

FIG.5.2. Cash flow diagram for a uniform series of payments.

The expression $1/(1+i)^N$, denoted $(P/F)^i_N$, is called the *single payment present worth factor* and, in this case, i is usually called the *discount rate.* (As discussed in Section 5.1.4 below, the discount rate may be significantly different from the interest rate.) This factor is used whenever a monetary amount is moved backward in time, i.e. it is used to determine the present value of money N periods in the past.

5.1.2.3. Uniform sinking fund formula

A fund established to accumulate a desired future amount of money at the end of a given length of time through the collection of a uniform series of payments is called a *sinking fund.* Each payment has a constant value A, which is called an *annuity,* and is made at the end of each of N interest periods, as shown in Fig.5.2. The total amount F at the end of N periods is the sum of the compound amounts of the individual payments. For example, the money invested at the end of the first period will earn interest for (N − 1) periods, so that its amount will be $A(1+i)^{N-1}$ at the end of N periods. Similarly, the payment at the end of the second period will amount to $A(1+i)^{N-2}$; the last payment, made at the end of the last period, will earn no interest. Therefore, by summing all the contributions and simplifying:

$$A = F\left[\frac{i}{(1+i)^N - 1}\right] \tag{5.3}$$

The expression $i/[(1+i)^N - 1]$, denoted $(A/F)^i_N$, is called the *sinking fund factor.*

5.1.2.4. Uniform series compound amount formula

A future sum F equivalent to a uniform series of end-of-period sums A can be determined by rearranging Eq.(5.3):

$$F = A\left[\frac{(1+i)^N - 1}{i}\right] \tag{5.4}$$

The expression $[(1+i)^N - 1]/i$, denoted $(F/A)^i_N$, is called the *uniform series compound amount factor.*

5.1.2.5. Uniform capital recovery formula

A uniform end-of-period payment A that is required to accumulate to a given present investment P, when the interest rate and number of periods are known, can be calculated by substituting Eq.(5.1) for F in Eq.(5.3):

$$A = P\left[\frac{i(1+i)^N}{(1+i)^N - 1}\right] \tag{5.5}$$

The expression $[i(1+i)^N]/[(1+i)^N - 1]$, denoted $(A/P)^i_N$, is called the *capital recovery factor.* This factor may also be expressed as the sum of the sinking fund factor and the interest rate, i.e. $(A/P)^i_N = (A/F)^i_N + i$. When the capital recovery factor is multiplied by a present debt, it gives the uniform end-of-period payment necessary to repay the debt in N periods with interest rate i.

To illustrate this important factor, at a 10% annual rate of interest on borrowed capital, the amount of each annual payment made for 30 years in order to repay a debt of \$9 426 914 is \$1 000 000 (i.e. 9 426 914 $(A/P)^{10\%}_{30}$). As illustrated in Fig.5.3, this uniform end-of-year payment is the sum of two components: (1) payments made to recover the principal (i.e. original amount of capital borrowed); and (2) interest charges on the borrowed capital. The breakdown of interest and repayment of principal in Fig.5.3 shows that nearly all of the \$1 000 000 annual payment in the early years of repayment is interest charged on the remaining principal, while, in the later years, repayment of principal is the dominant component.

5.1.2.6. Uniform series present worth formula

The present worth of a series of uniform end-of-period payments can be calculated by rearranging Eq.(5.5):

$$P = A\left[\frac{(1+i)^N - 1}{i(1+i)^N}\right] \tag{5.6}$$

The expression $[(1+i)^N - 1]/[i(1+i)^N]$, denoted $(P/A)^i_N$, is called the *uniform series present worth factor.*

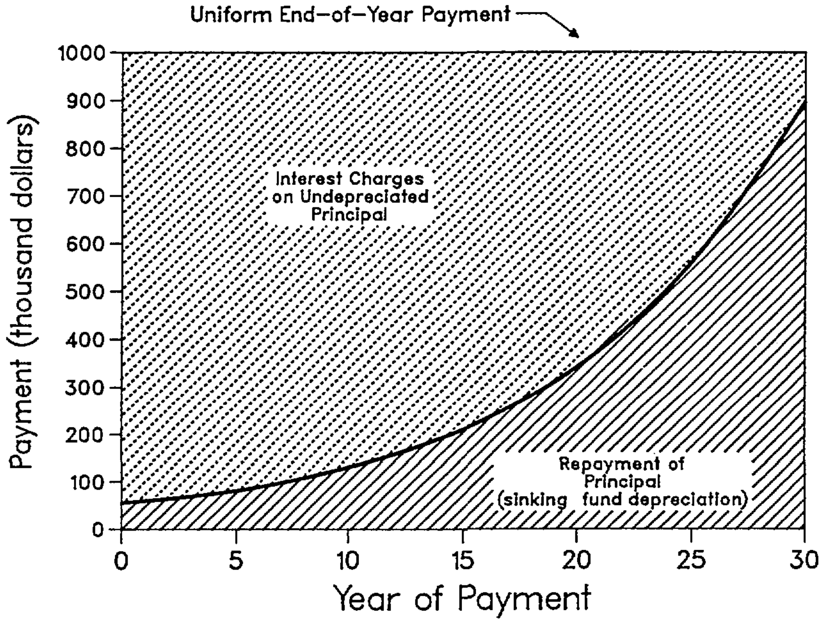

FIG.5.3. Illustration of capital recovery factor.

Table 5.I summarizes and briefly describes the six interest formulas. To simplify calculations, the six factors described in this section are usually tabulated for commonly used values of i and N and published in engineering handbooks and texts on finance and engineering economy.

5.1.3. Escalation and inflation

The effect of price escalation and inflation on the time value of money is an important consideration in long-range planning studies that involve costs occurring at a future time. *Inflation* refers to a rise in price levels caused by a decline in the purchasing power of a currency. Most societies operate within a framework of continuous rises in the general level of prices (i.e. inflation) although the rates of inflation vary widely from country to country and, within a given country, from one time period to another.

The term *escalation*, which also refers to a rise in prices, is usually classified as either real or apparent. *Real escalation* is defined as an escalation over and above the general rate of inflation and may result from factors such as resource depletion, new regulations and increased demand with limited supply. Real escalation is independent and exclusive of inflation. In contrast, the *apparent escalation* rate is defined as the total annual rate of increase in a cost. It includes the effects of both inflation and real escalation.

TABLE 5.I. SUMMARY OF INTEREST FORMULAS FOR ECONOMIC EVALUATIONS
(Assuming discrete time periods)

Name of formula	To find	Given	Equation	Use
Single compound amount	F	P	$F=P(1+i)^N$	Find a future sum equivalent to a present sum
Single present worth	P	F	$P=F\frac{1}{(1+i)^N}$	Find a present sum equivalent to a future sum.
Uniform series compound amount	F	A	$F=A\frac{(1+i)^N-1}{i}$	Find a future sum equivalent to a uniform series of end-of-period sums
Uniform sinking fund	A	F	$A=F\frac{i}{(1+i)^N-1}$	Find a uniform series end-of-period sum equivalent to a future sum
Uniform capital recovery	A	P	$A=P\frac{i(1+i)^N}{(1+i)^N-1}$	Find a uniform series end-of-period sum equivalent to a present sum
Uniform series present worth	P	A	$P=A\frac{(1+i)^N-1}{i(1+i)^N}$	Find a present sum equivalent to a uniform series of end-of-period sums

Variable definitions:
- P is a present sum of money
- F is a future sum of money at the end of N periods
- i is an interest or discount rate per period
- N is the number of interest or discounting periods
- A is an end-of-period payment (or receipt) in a uniform series of payments (or receipts) over N periods at i interest or discount rate.

The relationship between inflation, real escalation and apparent escalation is as follows:

$$(1+e)=(1+e')(1+f) \tag{5.7}$$

where e is the apparent escalation rate, e' is the real escalation rate, and f is the inflation rate. Assuming constant rates of inflation and escalation, the total annual increase in a cost over N time periods can be determined by multiplying the cost by the expression $(1+e)^N$, i.e. $C_N = C_0(1+e)^N$, where C_0 is the cost in a reference year and C_N is the cost N years later.

As an illustration of these concepts, consider the effects of escalation and inflation on the price of coal over the period from 1990 to 2000. Suppose that the price of coal (in US\$) in 1990 is \$1.00/10^9 J, and that the annual inflation rate over this period is 6%. Furthermore, assume that the price of coal will escalate over the 1990–2000 period at an average annual rate of 1.5% as a result of resource depletion (i.e. this escalation is independent of inflationary effects). The price of coal in the year 2000, expressed in 1990 dollars, can then be determined as follows:

$$\begin{aligned}\text{Coal price in year 2000 (year 1990 dollars)} &= (\text{coal price in 1990 dollars}) \times (1 + \text{real escalation rate})^{10} \\ &= \$1.00 \times (1.015)^{10}/10^9 \text{ J} \\ &= \$1.16/10^9 \text{ J}\end{aligned}$$

If the effects of inflation are included, then the coal price in the year 2000, expressed in year 2000 dollars, can be determined:

$$\begin{aligned}\text{Coal price in year 2000 (year 2000 dollars)} &= (\text{coal price in 1990 dollars}) \times (1 + \text{apparent escalation rate})^{10} \\ &= (\text{coal price in 1990 dollars}) \times [(1 + \text{real escalation rate})(1+\text{inflation rate})]^{10} \\ &= \$1.00\,(1.015 \times 1.06)^{10}/10^9 \text{ J} \\ &= \$2.08/10^9 \text{ J}\end{aligned}$$

Long-range planning studies can be performed by either including or excluding inflationary effects. In both cases, however, it is essential that all costs and economic parameters used in a study (e.g. the discount rate and escalation rates) be treated consistently. A study that includes the effects of inflation, such that monetary values are expressed in terms of actual prices of each year, is defined as being in terms of *current* (or nominal) monetary amounts, while a study that excludes the effects of inflation such that monetary values are expressed in terms of general purchasing power in a base year is defined as being in terms of *constant* monetary amounts. While both methods are allowable, it is recommended that expansion planning studies be performed in terms of constant monetary amounts. In this case, only real price escalation is included in the analysis. On the other hand, it is often convenient to perform financial and budgetary analyses that may include complex tax considerations in terms of current monetary amounts. Even when the analysis is performed using current monetary amounts, however, the final result can always be expressed in terms of a constant monetary amount.

5.1.4. Discount rate

The discount rate used in Eq.(5.2) for converting future sums to present equivalent sums is a critical economic parameter. It is defined as the rate of interest reflecting the time value of money that is used to convert benefits and costs occurring at different times to equivalent values at a common time. Theoretically, it reflects the opportunity cost of money to a particular investor (or, in broad terms, in a particular country). Therefore, because the opportunity cost of money is linked to the prevailing economic conditions within a given country, the discount rate, like the inflation rate, tends to vary, often significantly, from country to country. Developing countries often use discount rates substantially higher than those prevailing in industrial countries to reflect both the scarcity of capital and the much larger profitability of new investment projects that compete for limited financial resources.

In the case of a publicly owned tax-exempt utility that meets its investment needs by borrowing on a capital market where funds are available without limitation at a constant interest rate, the discount rate is equal to the interest rate prevailing on the market. This situation rarely occurs in the real world. From a more realistic viewpoint, state-owned utilities use a rate of discount suggested or imposed by the economic planning authorities that (ideally) should reflect the cost of capital in the national economy.

Different but no less complex problems arise in the determination of a suitable discount rate for a privately owned tax-paying electric utility whose capital needs are met by a combination of bond and stock financing in a proportion fixed by regulation or custom. In such cases, the rate at which expenditures and revenues must be discounted through time must be determined on a case-by-case basis and will involve the proportion of bond to stock financing as well as the income tax rate on gross profits. Privately owned electric utilities in the USA often use either the weighted average cost of capital (i.e. the rate of return associated with the entire pool of investors in the utility) or the average after-tax cost of capital as the discount rate. The discount rate for each case can be determined as follows:

$$\text{Weighted average cost of capital} = q_1 Q_1 + q_2 Q_2 + q_3 Q_3 \tag{5.8}$$

$$\text{Average after-tax cost of capital} = q_1 Q_1 + (1-T) q_2 Q_2 + q_3 Q_3 \tag{5.9}$$

where q_1, q_2 and q_3 are the fractions of capital from equity, debt and preferred stock, respectively, T is the effective income tax rate, and Q_1, Q_2 and Q_3 are the rate of return on equity investment, interest rate on debt, and interest rate on preferred stock, respectively. For national studies, taxes can be considered a transfer of payments and as such can usually be neglected. For the evaluation of bids, however, it is usually necessary to take into account all detailed economic effects, including tax considerations. The economic ground rules selected for an expansion planning study must clearly be carefully considered, and all parameters used in the study must be consistent with the ground rules set.

The discount rate, like the escalation rate defined in Eq.(5.7), can be defined as either including or excluding the effects of inflation. In general,

$$(1+i)=(1+i')(1+f) \tag{5.10}$$

where i is the apparent discount rate, i' is the real discount rate, and f is the inflation rate. When the apparent discount rate is used in a present worth analysis, the time stream of values is all effectively deflated to the reference year of the present worth calculation. For example, if the real discount rate is 4% and the prevailing long-term inflation rate is 6%, then the 1990 present worth value, in 1990 dollars, of \$1.00 in year 2000 dollars is \$0.38 (i.e. $\$1.00/[(1.04)(1.06)]^{10}$).

5.1.5. Economic comparisons using interest formulas

Economic comparisons between alternatives can be performed by using the interest formulas detailed in Table 5.I. Two widely used techniques for comparing alternatives are (1) *present worth analysis,* in which all cash flows are converted to the same point in time, and (2) *annual equivalent cost analysis,* in which all cash flows are converted to an equivalent annual annuity. Both techniques yield the same decision. These two techniques are applied in the following example to illustrate the use of the interest formulas.

Consider two alternative power plants (denoted (1) and (2)) with somewhat different economic characteristics. Each alternative has an initial investment cost I and an expected life N, and each incurs an annual operating cost (paid at the end of each year) of M.[3] Alternative (1) has a salvage value[4] V_1; alternative (2), which has no salvage value, incurs a one-time overhaul cost H_2 at time T_2 after startup. Cash flow diagrams for the two alternatives are shown in Fig.5.4. The startup time (or project beginning) is used as a reference point for comparison; all costs are assumed to be in constant dollars at time of startup. Although the present time or the beginning of a project are customarily chosen as reference points for comparison, any time can be selected. While this choice will not affect the decision, the magnitude of the difference between two alternatives will change.

To calculate the present worth values of the costs associated with the two alternatives, the formulas summarized in Table 5.I can be used. The annual

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[3] A number of simplifying assumptions have been made in this example. For instance, the initial investment costs of the alternatives are represented by a single number. As discussed elsewhere in this guidebook, determining the total capital investment associated with a power plant requires consideration of a variety of complex factors, such as fore costs, payment schedules, and interest during construction.

[4] Salvage value is defined as the net sum to be realized from the disposal of an asset (net of disposal costs) at the time of its replacement or resale, or at the end of the study period.

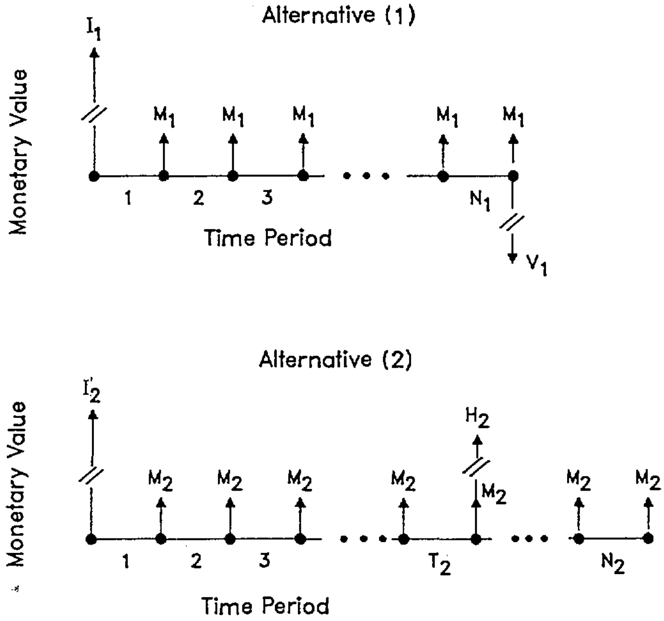

FIG.5.4. Cash flow diagrams for comparison of alternatives.

operating costs represent annuities, while the salvage and overhaul costs are future values. In each case, a present value is required. Assuming a discount rate i, the present worth values can be determined as follows:

$$\text{Present worth value for alternative (1)} \quad = I_1 - V_1(P/F)^i_{N_1} + M_1(P/A)^i_{N_1} \tag{5.11}$$

$$\text{Present worth value for alternative (2)} \quad = I_2 + H_2(P/F)^i_{T_2} + M_2(P/A)^i_{N_2} \tag{5.12}$$

The two present worth values can be compared only when $N_1 = N_2$, i.e. the alternatives must be compared on the basis of equal lifetimes. When $N_1 \neq N_2$ the analysis can be carried out by assuming that the alternatives will be replaced in the future by identical units possessing the same costs until the study periods are the same length. The shortest period will be the least common multiple of N_1 and N_2 (e.g. if $N_1 = 20$ and $N_2 = 30$, alternative (1) would be assumed to be replaced by two consecutive identical units, while alternative (2) would be assumed to be replaced by one identical unit, resulting in a 60 year study period).

As an alternative to the present worth approach, the annual equivalent costs of alternatives (1) and (2) can be determined by converting all costs to annuities using the formulas in Table 5.I (assuming a discount rate i):

$$\text{Annual equivalent cost for alternative (1)} = I_1(A/P)^i_{N_1} - V_1(P/F)^i_{N_1}(A/P)^i_{N_1} + M_1$$

$$= I_1 i + (I_1 - V_1)(A/F)_{N_1} + M_1 \quad (5.13)$$

$$\text{Annual equivalent cost for alternative (2)} = I_2(A/P)^i_{N_2} + H_2(P/F)^i_{T_2}(A/P)^i_{N_2} + M_2 \quad (5.14)$$

In contrast to the present worth approach, this procedure implicitly assumes that each alternative will be repeated, and repeated at the same costs as before so that the values obtained can be directly compared.

To illustrate the importance of the discount rate used in such an analysis, consider a choice between two proposed projects, A and B.[5] Project A is built in one year at an initial cost of $10 000. It then yields a declining stream of revenues over a five year period, as shown in Fig.5.5. The second project (B) takes two years to build, with a capital cost of $10 000 the first year and $5000 in the second year. However, it yields a level revenue stream over its five year lifetime, as shown in Fig.5.5.

Using present worth analysis, the present values of the two projects for a discount rate i can be calculated as follows:

$$\text{Present value of project A} = -10 + \frac{5}{(1+i)} + \frac{4}{(1+i)^2} + \frac{3}{(1+i)^3} + \frac{2}{(1+i)^4} + \frac{1}{(1+i)^5}$$

$$\text{Present value of project B} = -10 - \frac{5}{(1+i)} + \frac{6}{(1+i)^2} + \frac{6}{(1+i)^3} + \frac{6}{(1+i)^4} + \frac{6}{(1+i)^5}$$

Figure 5.6 compares the present worth values for the two projects as a function of the discount rate. If the discount rate is between 0 and about 13%, project B is preferred over project A because it has a larger present value. If the discount rate is between 13% and 20%, then project A is preferable. However, if the discount rate selected is greater than 20%, neither project should be selected because the present value is negative.

This example clearly illustrates the significance of the discount rate in selecting appropriate projects. In most analyses, a range of discount rates should be investigated to determine the sensitivity to this important economic parameter.

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[5] Adapted from Stokey and Zeckhauser (1978). This example excludes the effects of inflation.

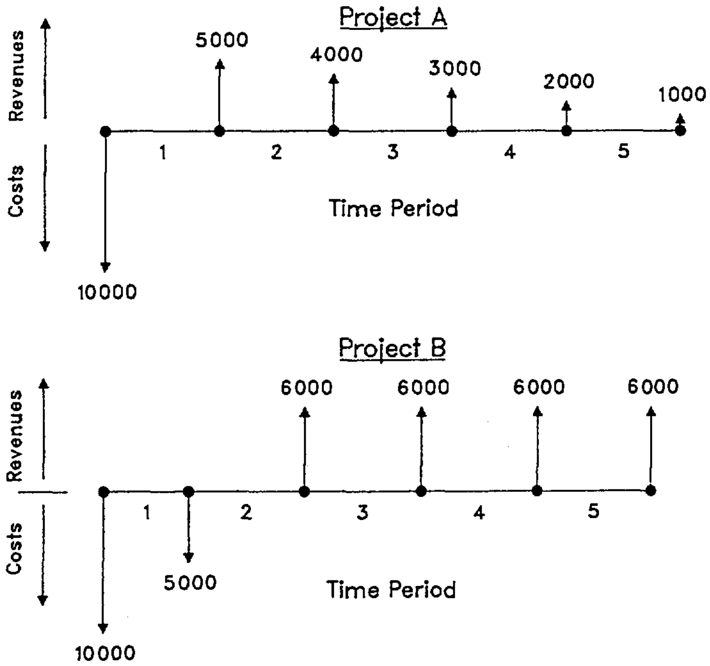

FIG.5.5. Cash flow diagrams of projects for comparison.

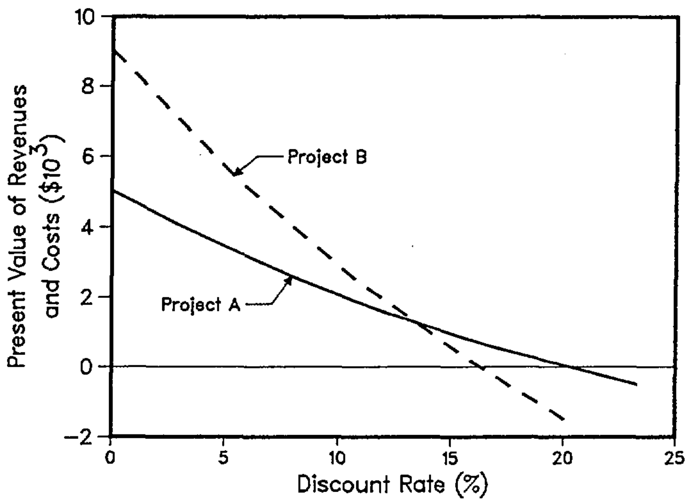

FIG.5.6. Present worth values of projects for comparison.

5.1.6. Depreciation

Power plants and their associated electric generation equipment, like all production equipment, decrease in worth over time as they wear out physically or are replaced by newer or more economic facilities. The term *depreciation* generally refers to this decrease in worth. In terms of cost accounting, however, the fundamental concept of depreciation is that the capital invested in a production facility, such as the initial capital invested in a power plant, must be recovered in some systematic fashion from the revenues it generates during its operating life. Therefore, from the viewpoint of accounting, depreciation is defined as the annual charge against revenues that is used to repay the original amount of capital borrowed from investors. As such, depreciation does not account for the replacement value of an asset which, owing to real escalation and inflation, may increase substantially over time with respect to its original purchase price. While depreciation accounting is important for financial analyses, it is of interest in expansion planning primarily from the standpoint of calculating a salvage value for generating units that have expected lifetimes extending beyond the end of the study period.

A variety of depreciation methods are available for cost accounting. Some methods are designed to increase cash flow in the early years of an investment, for example; while a number of others are designed for tax purposes. Whatever the methods used, however, the sum of all annual depreciation charges over the life of the alternative must equal the initial investment in the alternative less the salvage value.

Four commonly used depreciation methods are described in this section: (1) straight line, (2) sum-of-the-years digits, (3) declining balance, and (4) sinking fund. All four methods are based strictly on time, i.e. an asset has the same depreciation charge whether it is used continuously or only occasionally (for example, depreciation is independent of a power plant's electrical output). Each depreciation method has unique features, and the choice of a particular method is often influenced by factors such as income tax laws and regulations[6]. In many instances, specific depreciation methods are specified by regulatory agencies within a country.

The following notation is used in the development of the depreciation formulas:

I is the purchase price (present worth at time zero) of asset,
V is the net salvage value (i.e. a future value) at end of asset's useful life,
D_t is the depreciation charge at end of year t,
B_t is the book value of asset at the end of year t,[7]

[6] Refer to the engineering economics texts listed in the Bibliography at the end of the chapter for more detailed discussions of these concepts.

[7] The book value of an asset is equal to the original investment to be recovered minus all depreciation charges accumulated to date.

N is the useful life of asset in years, and
t is the number of years of depreciation from time of purchase.

5.1.6.1. Straight-line depreciation

The simplest and one of the most widely used of all depreciation methods is called straight-line depreciation, in which the depreciation charged each year is constant. The fraction of initial investment charged each year as depreciation is just the reciprocal of the service life of the asset, while the book value of the asset declines linearly with time:

$$D_t = \frac{1}{N}(I-V) \tag{5.15}$$

$$B_t = I - \frac{t}{N}(I-V) \tag{5.16}$$

When t = N, the book value is equal to the salvage value. The annual return on investment, which is a fixed fraction of the book value, also decreases linearly with time.

5.1.6.2. Sum-of-the-years digits depreciation

This depreciation method provides a larger depreciation charge in the early years of plant life (called accelerated depreciation), which may correspond more closely to the way an asset (e.g. a power plant) actually depreciates. The annual depreciation charge is the ratio of the digit representing the remaining years of plant life plus one, $(N-t+1)$, to the sum of the digits for the entire plant life, $(1+2+ \ldots +N)$, multiplied by the initial cost minus the salvage value:

$$D_t = \left[\frac{2(N-t+1)}{N(N+1)}\right](I-V) \tag{5.17}$$

$$B_t = I - \left[\frac{2Nt - t^2 + t}{N(N+1)}\right](I-V) \tag{5.18}$$

5.1.6.3. Declining balance depreciation

The declining balance method is another accelerated depreciation option for amortizing an asset at an accelerated rate early in its life, with corresponding lower annual charges near the end of service. In this method, a fixed rate is applied to the balance of the investment after the depreciation charges of previous years have been subtracted. When tax regulations permit (e.g. in the USA), a rate equal to twice the straight-line rate is used (i.e. 2/N); this is commonly called the double declining balance method. The formulas for calculating the depreciation charge and book value under the double declining balance method are:

$$D_t = I\left(\frac{2}{N}\right)\left(\frac{N-2}{N}\right)^{t-1} \tag{5.19}$$

$$B_t = I - I\left[1 - \left(\frac{N-2}{N}\right)^t\right] \tag{5.20}$$

Because this method will not lead to full depreciation in any finite time, a switch to some other depreciation method must be made. Typically, a change-over to straight-line depreciation is made in the year in which the straight-line depreciation on the remaining balance is just equal to the double declining balance depreciation.

5.1.6.4. Sinking fund depreciation

In this method, a constant annual charge for depreciation plus return on undepreciated investment is set at a value such that the net plant investment will be fully depreciated at the end of plant life. This method is analogous to establishing a fund by constant end-of-year annual deposits throughout the life of an asset. These deposits are then assumed to earn interest so that, at the end of plant life, the total fund will equal the cost of the asset minus its salvage value. The amount charged as depreciation in any year is equal to the sinking fund deposit plus the interest on the accumulated fund. Therefore, unlike the straight-line method, charges for depreciation are lowest at the beginning of life and increase with time. Book values with the sinking fund method are always greater than they would be with the straight-line method:

$$D_t = \left[\frac{i(1+i)^{t-1}}{(1+i)^N - 1}\right](I - V) \tag{5.21}$$

$$B_t = I - \left[\frac{(1+i)^t - 1}{(1+i)^N - 1}\right](I - V) \tag{5.22}$$

In terms of expansion planning, the sinking fund method of depreciation is the recommended approach for calculating the appropriate salvage values for new generating unit additions that have expected operating lifetimes extending beyond the end of the study period. If a unit with an expected life of N years operates for only M years, where $M < N$, the salvage value can be calculated as the initial cost minus the accumulated depreciation charges through year M:

$$V = I - \sum_{t=1}^{M} D_t \tag{5.23}$$

where D_t is calculated using the sinking fund method.

An important theorem in depreciation accounting states that, for any method of depreciation, the sum of present worths of annual charges for depreciation plus return on the investment remaining after depreciation charges for previous years equals the original investment minus the present worth of the salvage value:

$$\sum_{t=1}^{N} \left[\frac{D_t + i \left(I - \sum_{m=1}^{t-1} D_m \right)}{(1+i)^t} \right] = I - \frac{V}{(1+i)^N} \tag{5.24}$$

A comparison of the four depreciation methods (summarized in Table 5.II) is shown in Fig.5.7. The sinking fund method has the slowest rate of capital recovery, while the sum-of-the-years digits and double declining balance methods recover a large share of the initial investment early in the depreciable life. Combinations of these four methods are sometimes used by utility companies, although sum-of-the-years digits and double declining balance methods, both accelerated depreciation options, are typically used for tax purposes.

To illustrate the four depreciation methods, consider purchasing a piece of equipment at a cost of \$25 000. For an expected five year operating life and an estimated net salvage value (at the end of the fifth year) of \$10 000, the annual depreciation charges and end-of-year book values calculated using the four methods are compared in Table 5.III. A 10% annual rate of interest was used for the sinking fund calculations. In each case, the sum of annual depreciation charges equals the initial investment less the net salvage value, i.e. \$15 000, and the book value at the end of the fifth year is exactly equal to the salvage value. The depreciation allocation shown at the end of the second year for the double declining balance method reflects the fact that accrued depreciation, which by calculation would be \$25 000 (2/5)(3/5), or \$6000, must never exceed the depreciable base (I – V). Therefore, because \$10 000 was charged the first year, only \$5000 is permitted in the second year.

TABLE 5.II. SUMMARY OF SELECTED DEPRECIATION METHODS

Method	Depreciation charge at end of year t	Accrued (cumulative) depreciation at end of year t [a]
Straight line	$\frac{1}{N}(I-V)$	$\frac{t}{N}(I-V)$
Sum-of-the-years digits[b]	$\left[\frac{2(N-t+1)}{N(N+1)}\right](I-V)$	$\left[\frac{2Nt-t^2+t}{N(N+1)}\right](I-V)$
Double declining balance[b,c]	$I\left(\frac{2}{N}\right)\left(\frac{N-2}{N}\right)^{t-1}$	$\left[1-\left(\frac{N-2}{N}\right)^t\right]I$
Sinking fund	$\left[\frac{i(1+i)^{t-1}}{(1+i)^N-1}\right](I-V)$	$\left[\frac{(1+i)^t-1}{(1+i)^N-1}\right](I-V)$

[a] Accrued depreciation must never exceed $I-V$.
[b] Not allowed when $N<3$.
[c] A switch at any year to any of the other methods listed is allowed.

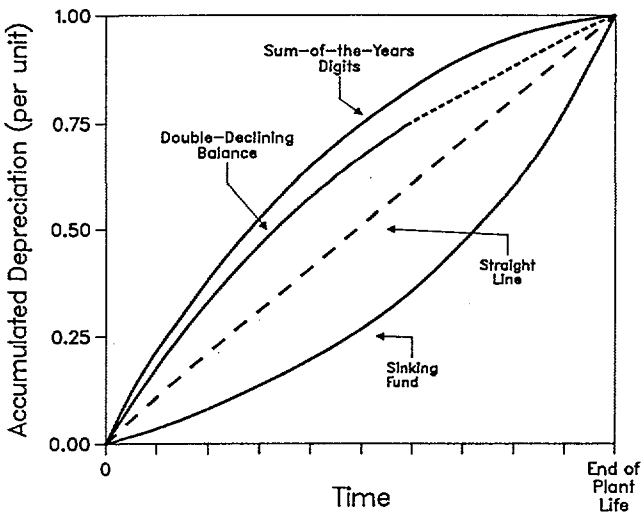

FIG.5.7. Comparison of depreciation methods.

5.2. CRITERIA FOR EVALUATION OF PROJECTS

Economic comparisons of alternative projects, such as comparisons of different types of power plants, can be performed in different contexts. The scope of an analysis, for example, may vary from the economic merit ranking of a few alternative plants that are available for commissioning at a given time in a specific power grid to an economic comparison of entire national programmes for the development of new power sources, including their supporting infrastructure. The criteria of economic choice used in such comparisons will vary accordingly. A power system economist, for example, may view the discount rate, which may be based on current market conditions, as a parameter beyond immediate control, while a national planner may include it among the interdependent variables of a planning model. Alternatively, taxes will be treated as costs by a privately owned electric utility but, from a national viewpoint, they are obviously a transfer of revenues for the nation and, as such, can be disregarded in national studies. The types of costs considered in the evaluation of projects are also important. A private utility company, for example, may consider only those costs that are directly connected with the production of electricity, while from the point of view of the public, external or social costs, such as those arising from environmental impacts and other social considerations, may be of particular concern. Pollution control equipment installed to meet environmental regulations illustrates the fact that external costs often become internalized over time.

The problems associated with macro-economic and micro-economic investment selection criteria and their consistency and reconciliation in different types of economic organizations are clearly important considerations, but these problems are beyond the scope of this summary. This section is limited to a review of three broad categories of criteria used by both private and state-owned power utilities in their economic comparisons of alternative power plants. These are: (1) criteria based on present worth values, (2) criteria based on yield, and (3) criteria based on payback or capital recovery time.

In the discussion that follows, individual investment projects are assumed to be characterized by time streams of revenues (or benefits) and costs, where R_t and C_t denote the revenues (benefits) and costs in year t, respectively. Both are measured in monetary terms. An expected project life of N time periods and a discrete rate of discount i are assumed in the mathematical expressions presented. The expressions in this section assume discrete time intervals and discounting. The reference point for discounting is the beginning of the first period of the cost and revenue streams. Similar expressions can also be derived using continuous discounting techniques.

5.2.1. Criteria based on present worth values

As described in Section 5.1.4, present worth analysis is a convenient mathematical tool designed to establish an equivalence between amounts of money or

TABLE 5.III. COMPARISON OF DEPRECIATION CHARGES AND BOOK VALUES FOR SELECTED METHODS OF DEPRECIATION ACCOUNTING*

Year	Depreciation charge for year ($)[a]				End-of-year book value ($)[b]			
	Straight line	Years digits	Declining balance	Sinking fund	Straight line	Years digits	Declining balance	Sinking fund
1	3000	5000	10 000	2457	22 000	20 000	15 000	22 543
2	3000	4000	5 000	2703	19 000	16 000	10 000	19 840
3	3000	3000	0	2973	16 000	13 000	10 000	16 867
4	3000	2000	0	3270	13 000	11 000	10 000	13 597
5	3000	1000	0	3597	10 000	10 000	10 000	10 000

* Assumes capital investment of $25 000, operating life of five years and salvage value of $10 000.

[a] The sum of all annual depreciation charges for each method equals the initial investment minus the salvage value (i.e. $15 000).

[b] The book value at the end of the fifth year for each method must equal the salvage value.

commodities available at different points in time. By the use of a discount rate, an irregular time series of expenditures or revenues can be transformed into a single value. The main difficulty in the present worth approach lies in the selection of a suitable rate of discount. However, as illustrated in Section 5.1.5, sensitivity studies can be performed to identify ranges over which analysis results are valid.

Four present worth criteria are described below: (1) maximum net present worth, (2) minimum present worth of costs, (3) minimum present worth of generating costs, and (4) benefit-to-cost ratio. It is important to note that the rankings provided by these criteria will not necessarily be the same.

5.2.1.1. Maximum net present worth

The most comprehensive of all present worth criteria involves ranking alternatives according to their net discounted profits, i.e. according to the difference between the present value of revenues (benefits) and the present value of costs. This criterion is often used in public policy analysis. Mathematically, the net present worth criterion can be expressed as follows:

$$\text{Net present worth} = \sum_{t=1}^{N} \frac{R_t - C_t}{(1+i)^t} \tag{5.25}$$

While this present worth criterion is rigorous, its application to the selection of a particular plant for a power generating system is somewhat academic because it would require:

(1) An estimate of future sales tariffs and an allocation of revenues to generating, transmission and distribution equipment; and
(2) In the general case of comparison between two types of generating equipment that are expected to render different services to the grid (e.g. a nuclear station and a hydroelectric reservoir plant with seasonal storage), a calculation of present worth values of all revenues and costs for the entire generating system assuming each alternative is added and operated over the entire life of the unit.

The second difficulty noted above is perhaps the most fundamental, although there are two ways to deal with it: (a) by assuming that the alternatives considered will render the same services to the grid (e.g. a case involving two nuclear power stations with identical lives and availabilities, and whose low fuel costs practically ensure base load duty) so that the future operation of the system remains unaffected by the selection of either plant, or (b) by introducing appropriate corrections to take into account both the unequal services expected from each alternative and the future differences of the costs to the rest of the system that would be caused by its selection.

5.2.1.2. Maximum present worth of costs

With appropriate assumptions or corrections for equality of service expected from each of the alternatives considered, the first difficulty noted for the criterion of maximum net present worth can easily be removed by substituting the criterion of minimum present worth of costs:

$$\text{Present worth of costs} = \sum_{t=1}^{N} \frac{C_t}{(1+i)^t} \tag{5.26}$$

where C_t represents the anticipated cost stream.

5.2.1.3. Minimum present worth of generating costs

If properly applied, the criterion of generating costs does not differ in substance from that of the present worth of total costs. It does, however, automatically correct for inequalities such as differences of size and estimated operating lives, and at the same time allows a somewhat simpler presentation of the results. The unit generating cost of a station whose construction, fuelling and operation involve a cost stream C_t, and whose energy output over time is expected to be E_t, is defined as:

$$\text{Present worth of generating costs} = \frac{\displaystyle\sum_{t=1}^{N} \frac{C_t}{(1+i)^t}}{\displaystyle\sum_{t=1}^{N} \frac{E_t}{(1+i)^t}} \tag{5.27}$$

This definition of unit generating costs may appear at the same time too simple and too abstract. Its application, however, presupposes a whole series of side calculations for determining the distribution of costs over time (C_t) and the schedule of future energy production (E_t). (Refer to Section 6.2 for a detailed discussion of this measure.) In addition, these generating costs will usually be quite different from those sometimes computed by selecting a 'typical' year of operation, computing annual fixed capital, fuel, operation and maintenance costs, and dividing by the annual energy production. Not only is the latter practice usually incorrect, but its apparent simplicity is misleading because it often requires, on one hand, a choice of a method of depreciation for the computation of fixed charges and, on the other, a series of averaging operations to smooth out irregularities such as outlays for nuclear fuels.

5.2.1.4. Benefit-to-cost ratio

This criterion, sometimes used in the analysis of large power and water projects, involves ranking alternative projects by the ratios of the present worth values of revenues to the present worth values of costs:

$$\text{Benefit-to-cost ratio} = \frac{\displaystyle\sum_{t=1}^{N} \frac{R_t}{(1+i)^t}}{\displaystyle\sum_{t=1}^{N} \frac{C_t}{(1+i)^t}} \tag{5.28}$$

This formulation gives a measure of the discounted benefits per dollar of discounted costs.

In general, this criterion, like all criteria based on ratios, is open to serious methodological objections. For example, the sizes of competing projects (in terms of benefits and costs) are not revealed in the resultant ratios. Furthermore, it is seldom applied in power equipment comparisons because of the difficulty already mentioned of determining R_t for different projects and because, if revenues are assumed to be identical for all projects, it reduces to the criterion of minimum present worth costs.

The advantages and drawbacks of present worth analysis are clear. It provides a systematic treatment of irregular time flows of costs and revenues and, in the process, makes it necessary to state explicitly all assumptions on important cost items, such as future fuel costs. Furthermore, it permits (at least in the case of tax-free utilities) the difficult question of depreciation to be disregarded completely. The major difficulty is the selection of a suitable rate of discount. To overcome this, attempts have been made to devise criteria which would be based solely on the costs and revenues of the projects compared, without recourse to any extraneous parameter.

5.2.2. Criteria based on yield

Two criteria based on yield are presented: (1) that of internal rate of return, and (2) that of relative yield. The rankings provided by these criteria will not necessarily be the same as any of the ranking provided by the present worth criteria.

5.2.2.1. Criterion of internal rate of return

The yield, or internal rate of return, of an investment with revenue and cost streams R_t and C_t, respectively, is defined as the rate of discount at which the net present worth of the operation becomes zero. To distinguish the internal rate of return from the conventional discount rate, the symbol r is used in the formulation:

$$\text{Internal rate of return:} \quad \sum_{t=1}^{N} \frac{R_t - C_t}{(1+r)^t} = 0 \tag{5.29}$$

Once again, in spite of its abstract appearance, this equation reduces to quite familiar concepts when applied to simple cases. Thus, if an operation involves an investment of \$100 and permanent annual benefits of \$7, its yield is 7% because an infinite chain of payments of \$7 will have a present worth value of \$100 if discounted at the rate of 7%.

The corresponding criterion consists of ranking investments according to their yields, thus avoiding the use of any externally established rate of discount. This apparent advantage is offset by a number of serious objections. Ranking by yield would indeed be correct if a limited budget were to be allocated between entirely independent investment alternatives. However, if some of these alternatives are mutually dependent or, as is often the case in power plant comparisons, mutually exclusive, the use of the yield criterion can lead to absurdities. Furthermore, the determination of the revenue function R_t, attributable to a power plant in an interconnected system, gives rise to the difficulties already mentioned in the case of present worth valuation. To avoid the last difficulty, the concept of relative yield may be used.

5.2.2.2. Criterion of relative yield

Given two alternatives (denoted by the superscripts 1 and 2) with revenue and cost streams R_t and C_t, respectively, the relative yield (defined as r′) of alternative 2 with respect to alternative 1 is defined as the rate r′ at which the difference of their net present worth values is equal to zero. The relative yield r′ is given by the following equation:

$$\text{Relative yield:} \quad \sum_{t=1}^{N} \frac{(R_t^2 - C_t^2) - (R_t^1 - C_t^1)}{(1+r')^t} = 0 \tag{5.30}$$

A simplified illustration will help to make the meaning of this definition clear. In the case of two plants expected to perform the same services but with different investment costs I_1 and I_2 and annual fuel costs F_1 and F_2, such that $I_1 < I_2$, $F_1 > F_2$, the rate defined by Eq.(5.30) is merely the yield on the incremental investment $I_2 - I_1$ as a result of the annual fuel savings $F_1 - F_2$.

5.2.3. Criteria based on payback or capital recovery time

Criteria based on payback time have often been applied to plant selection both in planned economies and in private enterprise. In general, the payback time T' of an investment with revenue and cost streams R_t and C_t, respectively, is defined by the equation:

$$\text{Payback period:} \quad \sum_{t=1}^{T'} (R_t - C_t) = 0 \tag{5.31}$$

Projects with a short payback period are generally deemed preferable to those with a longer payback period. However, rankings based on this criterion ignore the benefits and costs that extend beyond the payback period and are often criticized as being 'nearsighted'.

If the cost stream C_t is broken down into an investment (I) that is made at one point in time, and variable costs (F_t) covering, for instance, fuel, operation and maintenance costs in the case of a power plant, this equation can be written in the following form:

$$I = \sum_{t=1}^{T'} (R_t - F_t) \tag{5.32}$$

In this form, time T' clearly appears as the time required for net operational revenues to pay back the capital investment. The corresponding criterion consists in ranking alternatives by their payback times and choosing only those whose time of capital recovery does not exceed a preselected value T'_0.

The payback criterion described in Eq.(5.32) has been subjected to various modifications by different definitions of the variable costs. Thus, for instance, in certain planned economies, power plant variable costs are defined as including not only fuel, operation and maintenance expenditures, but also straight-line depreciation of the investment over its life N, so that the equation defining T' must be rewritten as follows:

$$I = \sum_{t=1}^{T'} \left(R_t - F_t - \frac{T'}{N} \right) \tag{5.33}$$

The criterion of payback time may be attractive in its relative simplicity, although the selection of a reference payback time produces the same problems as the choice of a suitable rate of discount. The main objection lies in the fact that this criterion ignores to a large extent the time distribution of costs and revenues within the payback period. Thus, two investment projects with the same investment cost of \$100 but with net revenues consisting of a series of five equal annual amounts of \$20 for one case and of a single amount of \$100 in the fifth year for the second, would both have the same payback time of five years and be considered economically equal, an obviously questionable ranking.

5.2.4. Summary

In summary, while it might be desirable to define a criterion that could be used to rank the different economic criteria surveyed in this section, the suitability of a criterion of comparison is usually relative. In the case of an environment where a rate of discount can be reasonably established, present worth analysis is certainly the most comprehensive approach. When this rate is unknown or fixed at an obviously artificial level, the rate of return might provide more useful indications. Finally, even payout times might be useful for quick preliminary assessments. In the case of power plant selection, the suitability and relevance of an economic criterion in a specific situation will to a great extent depend upon the degree of precision with which the data required for its application can be estimated.

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Chapter 6

GENERATING SYSTEM COSTS

This chapter presents techniques that are helpful in determining the components of the costs of a generating system. Some methods for simplified comparisons between alternative generating units, such as lifetime levelized cost, are developed from the economic principles presented in Chapter 5. Key factors in determining generating system costs, such as forced outage rates and incremental heat rates, are reviewed in some detail in preparation for the example calculation of production cost that follows. The advantages and limitations of a less rigorous method, known as screening curves, which is sometimes used to estimate output from generating units and least-cost capacity mixes, are presented in the final section.

The examples in this chapter are related primarily to greatly simplified thermal generating systems. The additional considerations and complications encountered in analysing mixed thermal-hydro systems are briefly noted here and are presented more fully in Chapter 8.

6.1. DEFINITION OF COSTS

This section defines and briefly discusses the types of costs associated with electric power generating plants and systems. Appendix H discusses some of these basic concepts in greater detail together with illustrative economic data for alternative power plants. Cost accounting practices and terminology vary from country to country and, in many instances, within countries. Furthermore, special terminology and conventions are often used in conjunction with specific types of generating unit, such as coal and nuclear power plants. Therefore, while the terminology and conventions presented in this section are typical, they are not universal and are intended only to illustrate the basic concepts and categories of costs for power plants and electric generating systems. Some of the terms defined here may be defined differently elsewhere depending on the cost accounting system used or the type of analysis being performed.

6.1.1. Basic cost concepts

From an economic point of view, it is desirable (but seldom possible) to expand a power generating system by adding plants that are both cheap to build and that produce electrical power at the lowest possible cost. Two distinct figures of merit are therefore important when discussing or comparing the economics of

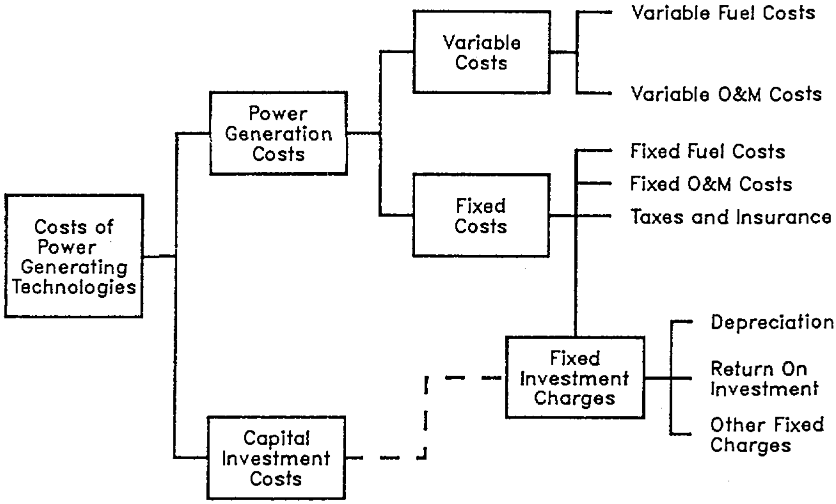

FIG. 6.1. Categories of costs for power generating technologies.

power generating technologies: (1) *capital investment costs,* expressed in \$/kW[1] of installed capacity, that denote the capital outlay necessary to build a power plant; and (2) *power generation costs,* expressed in mills/kW·h of generation[2], that represent the total cost of generating electricity. Power generation costs consist of the costs associated with the initial capital investment in a power plant *(fixed investment charges),* fuel costs, and operation and maintenance (O&M) costs. For discussion, these costs can be divided into two broad categories: *fixed costs* and *variable costs.* A breakdown of the general categories of costs for power generating technologies is presented in Fig.6.1. As illustrated, fuel and O&M costs have both fixed cost and variable cost components. The dashed line indicates that the fixed investment charges are a function of the capital investment costs. The levels of costs for the cost categories identified in Fig.6.1 will vary considerably depending on the technology examined. For example, nuclear power plants are characterized by high capital investment costs and low fuel costs, while no fuel costs are usually associated with a hydroelectric power plant.

Fixed costs are related to the expenditures for items used over an extended period of time, such as a boiler or reactor, and are independent of the amount of electricity generated by the plant. Fixed investment charges, which include depreciation (i.e. the annual charge for recovering the initial capital investment in a power plant), return on investment (for private utilities in the USA, for example,

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[1] As in Chapter 5, for convenience, all examples in this chapter are in US dollars.
[2] A mill is defined as 1/1000 of a monetary amount.

this includes interest paid to bondholders (debt) and return to stockholders (equity)) in addition to (where applicable) interim replacement and funds for decommissioning, all of which may be treated as proportional to the initial capital investment in plant and facilities, are classified as a fixed cost. The annual fixed investment charges for a plant can be calculated as the product of the *fixed charge rate* and the plant capital investment costs. In the absence of tax and insurance complications, which are very important considerations in some countries, the annual fixed charge rate is equal to the sum of the charges for depreciation and for the annual return on investment. Typical fixed O&M costs include wages and salaries, while fixed fuel costs could include, for example, the costs associated with stockpiling fuel (e.g. coal).

In contrast, variable costs, often called *expenses,* represent expenditures for goods and services consumed within a relatively short period of time (usually one year or less). Variable costs generally depend directly on the amount of electricity generated (i.e. they are expressed in terms of a monetary amount per kW·h production). Variable fuel costs and variable O&M costs are the two primary categories of variable costs.

From a utility point of view, the money received from customers, called *revenue,* must in the long run be sufficient to cover all costs of providing service. (this may not be the case in countries where electricity production is subsidized). Therefore, the annual *revenue requirement* is simply defined as the sum of the annual fixed and variable costs associated with all plants in the utility system. Variable costs are usually paid from annual revenues, while total investment costs must normally be recovered over an extended period of time because annual revenues would normally be insufficient to cover large capital expenditures. In addition, fixed costs represent money spent for items whose usefulness continues for a long time (e.g. a power plant), thereby producing benefits for both present and future customers. As a result, utilities often obtain revenue from customers through two kinds of service charges: (1) a *demand charge,* which depends on the maximum number of kW of power the utility contracts to supply, and (2) an *energy charge,* which depends on the total number of kW·h of electricity actually consumed. The demand charges are based on the fixed costs while the energy charges are based on the variable costs.

For purposes of analysis, utility system economics can be examined in terms of (a) overall revenue requirements and (b) production costs. *Revenue requirements analysis* refers to an economic analysis of both fixed and variable costs of providing service. In contrast, *production cost analysis* is only concerned with the costs which vary with the level of unit or system generation (i.e. variable fuel and variable O&M costs). Production cost analysis is used as a basis for determining economic loading order (Section 6.3) and is useful for examining the changes in utility system costs associated with fuel substitutions and unit outages.

Capital investment cost, fuel costs and O&M costs, the three major types of costs associated with power generating technologies, are discussed in the next subsections.

6.1.2. Capital investment costs

The capital investment cost denotes the total capital outlay necessary to build a power plant and bring it into commercial operation. For hydroelectric, coal and nuclear power plants, the fixed investment charges (which are proportional to the capital investment costs) are the largest contributor to power generation costs.

Total capital investment costs include the construction or overnight costs[3] of building the power plant, commonly referred to as fore costs, and costs related to escalation and interest charges accrued during the project period. Fore costs are generally divided into direct and indirect costs, comprising what is commonly referred to as base costs, and include items such as owner's costs, spare parts costs and contingencies.

Table H.1 in Appendix H shows the structure of capital investment costs for a power plant. The direct capital costs are directly associated on an item-by-item basis with the equipment and structures that comprise the complete power plant (e.g. boiler/reactor, turbine and electric plant equipment), land and land rights, and special materials, e.g. the initial loading of coolant and moderator materials for nuclear power plants. (Transmission plant costs, such as for the main power transformers, are, when considered, also classified as direct capital costs.) The direct costs can be divided into *depreciating* and *non-depreciating* assets. The depreciating capital costs are all capital costs, with the exception of land and (when used) reactor-grade heavy water inventory. The indirect capital costs are expenses of a more general nature and consist mainly of expenses for services (e.g. construction, engineering and management services), temporary facilities, and rentals. Taxes, duties and fees are excluded in national planning studies because they are normally recycled in the national economy.

Plant capital costs are sensitive to numerous factors, including the plant site (e.g. geographical location, subsurface conditions, site meteorological conditions, and proximity to population centres), length of construction schedule, unit size, effects of escalation during construction, interest rates and regulatory requirements. The addition of flue gas desulphurization equipment on coal-fired power plants, for example, can substantially increase the total cost of each generating unit.

6.1.3. Fuel costs

The terms *fuel cost* and *fuel cycle cost* refer to those charges that must be recovered in order to meet all expenses associated with consuming and owning fuel in a power plant. In general, cost analysis of nuclear fuel is more complicated than that for a power plant using a conventional fuel (e.g. coal, oil or gas), partly because conventional fuels are essentially consumed instantaneously while a single

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[3] Overnight construction costs refer to construction costs at a particular point in time, i.e. assuming instantaneous construction.

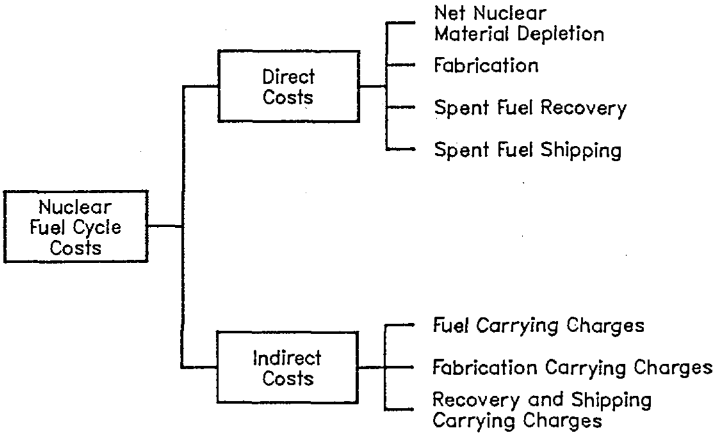

FIG. 6.2. Breakdown of nuclear fuel cycle costs.

batch of nuclear fuel may be used in a reactor for several years and then recycled. There are also many different types of nuclear fuel cycles, each of which may be composed of a large number of time-dependent steps (e.g. mining, milling, conversion, enrichment, fabrication, irradiation, storage, shipping, reprocessing and waste disposal).

Figure 6.2 shows a breakdown of nuclear fuel cycle costs. The direct costs refer to the expenses for materials, processes and services required to put the fuel into a form in which energy can be extracted. The direct cost item in Fig.6.2 labelled 'net nuclear material depletion' is the difference between the cost of fuel (e.g. ^{235}U and ^{238}U) supplied to a reactor and, provided reprocessing is an available option, the credit for fuel recovered after discharge from the reactor. The 'spent fuel recovery' category includes (when appropriate) reprocessing, reconversion and waste disposal costs.

In addition to the actual costs of carrying out each of the fuel cycle operations, there are the interest costs, or *carrying charges,* on investments. These indirect costs are the result of the time separation between expenditures for fuel and revenues from the sale of energy generated with the fuel. For example, fuel used in a light-water reactor is typically irradiated for three years and is then stored at the reactor site for another multiyear period. These and other time lags between fuel cycle operations lead to extensive carrying charges. For conventional fuels, coal and oil stockpiling may also lead to significant carrying charges. A methodology for calculating nuclear fuel cycle costs can be found in Appendix F.

6.1.4. Operation and maintenance (O&M) costs

O&M costs include all non-fuel costs that are not included in the fixed cost category. They include items such as the direct and indirect costs of labour and

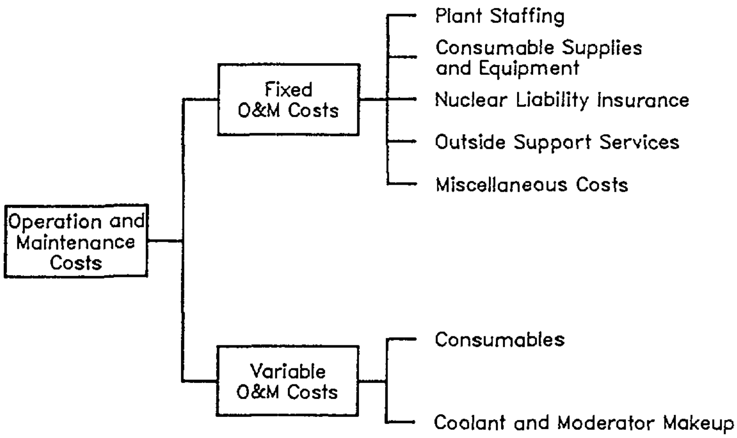

FIG.6.3. Breakdown of nuclear power plant O&M costs.

supervisory personnel, consumable supplies and equipment, outside support services, and (if applicable) moderator and coolant makeup and nuclear liability insurance. Reactor decommissioning costs are sometimes included as an O&M cost or as an economic adjustment to total annual costs. Typically, O&M costs are estimated on the basis of an average capacity factor for a power plant operating in its normal load-following manner.

Power plant O&M costs are generally divided into fixed and variable cost components, as the example in Fig.6.3 shows for a nuclear power plant. The fixed O&M costs ($/kW per year) are determined by the size and type of plant and are independent of the plant capacity factor. The variable O&M costs (mills/kW·h) vary directly with production (i.e. with capacity factor). Some cost accounting systems classify separately, as *consumable O&M costs,* the cost of all materials other than fuel consumed during operation of the plant. The cost of limestone used in a sulphur removal system is an example of a consumable O&M cost.

Working capital is usually regarded as a non-depreciating investment, and the annual fixed charges on this item must be added to the fixed O&M costs. Plant working capital is composed of two parts: the average net cash required for plant operations, and the value of the inventory of materials and supplies.

6.2. POWER PLANT LIFETIME LEVELIZED COST OF GENERATION

The annual revenue requirement for a particular power generating technology or for an entire electric utility system was described in the previous section as being comprised of a series of annual fixed and variable costs. These costs typically vary from year to year; variable costs, such as variable fuel costs, may change over time owing to price escalation, while fixed costs, such as those related to capital investment costs, may also vary owing to decisions about tax and depreciation schedules. Depending on prevailing economic conditions and the specific characteristics of the operating utility, these annual changes in fixed and variable costs may occur uniformly or in a highly irregular fashion.

In addition to changing costs, the kilowatt-hours of electricity generated by an individual power plant (or by an entire electric utility system) also typically vary from year to year owing to factors such as hydrological conditions and scheduled and unscheduled maintenance. The capacity factor for a nuclear or hydroelectric plant, for example, which is one commonly used measure of overall operating performance, typically varies over the unit's operating life. Varying load patterns caused by variable customer demands also significantly affect power plant operation.

The year-to-year variations in costs and electrical generation cause the power generation cost (expressed in mills per kilowatt-hour of net electricity produced) for an alternative plant or system to vary from year to year, making cost comparisons between generation alternatives extremely difficult. It is therefore convenient to use the present worth analysis techniques described in Section 5.1 to calculate a fictitious cost, called a levelized power generation, or bus bar, cost (in mills/kW·h), that is representative of the generating characteristics of the plant or system under consideration and the time-varying costs actually incurred. The concepts and methodology of cost levelization are presented and discussed in this section.

6.2.1. Basic concepts of cost levelization

The concept of cost levelization is illustrated in Fig.6.4. Shown as a function of time for a hypothetical power generation alternative are varying annual revenue requirements, R_t, expressed in current end-of-year dollars, and an equivalent current dollar levelized revenue requirement $\bar{R}$. Instead of collecting revenue R_t at the end of year t to pay for all fixed and variable costs incurred in that year, these costs could be recovered by receiving revenue of

$$\frac{R_t}{(1+i)^t} \tag{6.1}$$

at time zero, which is defined as the beginning of the first year of the revenue stream, and investing it to obtain a return at the rate of i per year for t years. Equation (6.1) is simply the present worth value of the revenue requirement in year t, where i is the apparent discount rate. As discussed in Section 5.1.4, the discount rate must be consistent with the economic data being analysed. In this case, an apparent discount rate, which includes the effects of inflation, must be used to be consistent with the revenue stream, R_t, which is expressed in current dollars.

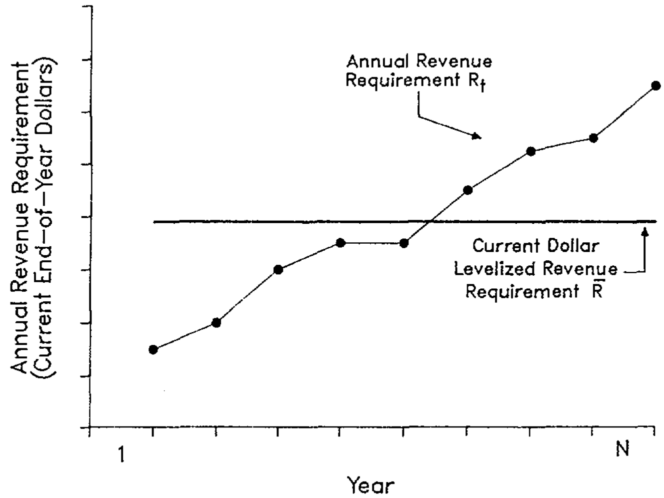

FIG. 6.4. Comparison of annual revenue requirements and levelized revenue requirement.

More generally, all costs occurring over the N-year lifetime of an alternative could be recovered by receiving revenues amounting to

$$\sum_{t=1}^{N} \frac{R_t}{(1+i)^t} \tag{6.2}$$

at the start of plant operation. This sum is the present worth of all annual costs incurred during the life of the alternative.

If a uniform revenue requirement, $\bar{R}$, was received each year over the life of the alternative (i.e. for N years), then the present worth of its revenues, namely,

$$\sum_{t=1}^{N} \frac{\bar{R}}{(1+i)^t} \tag{6.3}$$

would have to equal the sum of the present worths of the actual annual revenue requirements. The current dollar levelized revenue requirement can therefore be determined by equating Eqs (6.2) and (6.3) and solving for $\bar{R}$:

$$\sum_{t=1}^{N} \frac{\bar{R}}{(1+i)^t} = \sum_{t=1}^{N} \frac{R_t}{(1+i)^t} \tag{6.4}$$

or

$$\bar{R} = \frac{\displaystyle\sum_{t=1}^{N} \frac{R_t}{(1+i)^t}}{\displaystyle\sum_{t=1}^{N} \frac{1}{(1+i)^t}} \tag{6.5}$$

As described in Section 5.1.2, the denominator of Eq. (6.5) is simply the uniform series present worth factor with parameters i and N, which is equivalent to the inverse of the capital recovery factor $(A/P)_N^i$. To simplify the notation in this section, the abbreviation CRF is used for the capital recovery factor $(A/P)_N^i$. The current dollar levelized revenue requirement can thus be expressed as follows:

$$\bar{R} = \mathrm{CRF} \sum_{t=1}^{N} \frac{R_t}{(1+i)^t} \tag{6.6}$$

where

$$\mathrm{CRF} = \left[\sum_{t=1}^{N} \frac{1}{(1+i)^t} \right]^{-1} = \frac{i(1+i)^N}{(1+i)^N - 1} \tag{6.7}$$

Equation (6.6) defines the functional form for calculating a current dollar levelized cost, and implies that a levelized cost is essentially an average of individual annual costs each weighted by the present worth factor for the appropriate year.

Levelized costs can also be expressed in terms of constant monetary amounts. If R_t' represents the revenue requirement in year t expressed in constant dollars referenced to the beginning of the first year of the revenue stream, then

$$R_t = R'_t (1+f)^t \tag{6.8}$$

where f is the inflation rate as defined in Section 5.1.3. A constant dollar levelized revenue requirement, $\bar{R}'$, can be defined by equating its present worth value to the present worth value of the constant dollar revenue stream (as defined in Eq. (6.4) for current dollar values):

$$\sum_{t=1}^{N} \frac{\bar{R}'}{(1+i')^t} = \sum_{t=1}^{N} \frac{R'_t}{(1+i')^t} \tag{6.9}$$

where i' is the real discount rate with $i' = [(1+i)/(1+f) - 1]$, as defined in Eq. (5.10).

Solving Eq. (6.9) for $\bar{R}'$, and simplifying by using the notation CRF$'$ to denote the capital recovery factor $(A/P)_N^{i'} = [i'(1+i')^N]/[(1+i')^N - 1]$,

$$\bar{R}' = \mathrm{CRF}' \sum_{t=1}^{N} \frac{R'_t}{(1+i')^t} \tag{6.10}$$

Equation (6.10) defines the functional form for calculating a constant dollar levelized cost. If Eq. (6.8) is substituted for R'_t in Eq. (6.10), the following equivalent relationship can be derived:

$$\bar{R}' = \mathrm{CRF}' \sum_{t=1}^{N} \frac{R_t}{(1+i)^t} \tag{6.11}$$

Comparison between Eq. (6.6), which defines a current dollar levelized cost, and Eqs (6.10) and (6.11), which define a constant dollar levelized cost, reveals that the only difference between the expressions is the form of the capital recovery factor. Both approaches result in a fictitious cost that can be used for making economic comparisons between alternatives, and, in each case, the sum of the present worths of the actual annual revenue requirements must equal the sum of the present worths of the revenues produced by the fictitious cost. The current dollar levelized cost, which remains the same each year during the life of the facility in current dollar terms, is not referenced to any single year's buying power. On the other hand, the constant dollar levelized cost is expressed in terms

TABLE 6.I. ANNUAL REVENUE REQUIREMENT FOR A HYPOTHETICAL POWER PLANT WITH TEN-YEAR OPERATING LIFE

Year	End-of-year revenue requirement (Current $)	Equivalent revenue requirement (Constant end-of-year 1990 $)[a]
1991	40 000	37 736
1992	43 000	38 270
1993	47 000	39 462
1994	48 000	38 020
1995	52 000	38 857
1996	55 000	38 773
1997	58 000	38 573
1998	60 000	37 645
1999	63 000	37 290
2000	68 000	37 971
Present worth value[b] (end-of-year 1990 $):	310 500	310 500

[a] Inflation rate is 6%. Values in this column are obtained by dividing current dollar end-of-year revenue requirements by $(1.06)^{m-1990}$, where m is defined as the year of plant operation.

[b] Real discount rate is 4%; apparent discount rate is $(1.04)(1.06) - 1 = 0.1024$ or 10.24%.

of a reference year's dollars (i.e. it is referenced to the beginning of the first year of the revenue stream), and does not change over time in real terms although the actual year-by-year costs will rise in current dollar terms at the rate of inflation. Therefore, the constant dollar levelized cost approach, which provides a cost that is referenced to a particular year's buying power, is easier to interpret than its current dollar counterpart and is the recommended approach for levelized cost analysis.

To illustrate these concepts, suppose that the stream of current dollar annual revenue requirements for a hypothetical power generation alternative that begins commercial operation on 1 Jan. 1991 varies over its ten year operating life, as shown in Table 6.I. An equivalent annual revenue requirement, expressed in constant end-of-year 1990 dollars, is also shown in Table 6.I for an assumed 6% annual rate of inflation. For a real discount rate of 4% per year (which implies an

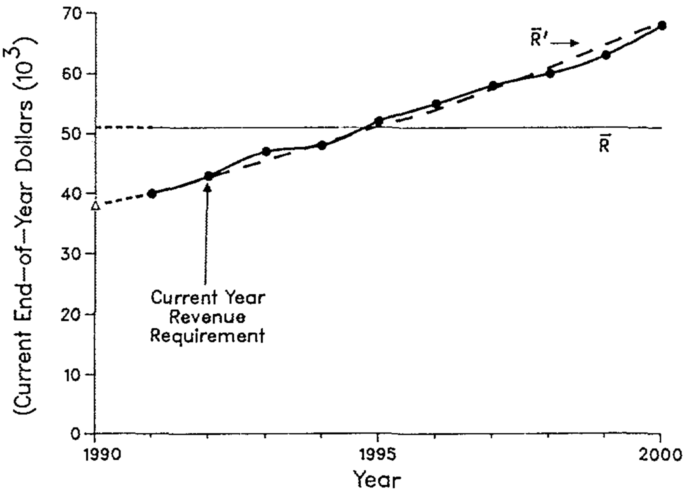

FIG. 6.5. Comparison of levelized costs in current dollars.

apparent discount of 10.24% per year), current and constant dollar levelized revenue requirements can be calculated using Eqs (6.6) and (6.10):

$$\bar{R} = \left|\frac{0.1024\,(1.1024)^{10}}{(1.1024)^{10} - 1}\right| \left|\frac{40\,000}{(1.1024)^1} + \frac{43\,000}{(1.1024)^2} + \ldots + \frac{68\,000}{(1.1024)^{10}}\right|$$

$$= [0.1644]\,[310\,500] = \$51\,055$$

$$\bar{R}' = \left|\frac{0.04\,(1.04)^{10}}{(1.04)^{10} - 1}\right| \left|\frac{37\,736}{(1.04)^1} + \frac{38\,270}{(1.04)^2} + \ldots + \frac{37\,971}{(1.04)^{10}}\right|$$

$$= [0.1233]\,[310\,500] = \$38\,282$$

The current dollar levelized revenue requirement of \$51 055 represents a charge that does not change with time in current dollar terms. However, it cannot be associated with the actual buying power in any particular year. In contrast, the constant dollar levelized revenue requirement of \$38 282 is expressed in terms of end-of-year 1990 dollars. This charge will increase over time in current dollar terms at the rate of inflation but will remain the same in constant dollar terms. Figures 6.5 and 6.6 illustrate these important concepts.

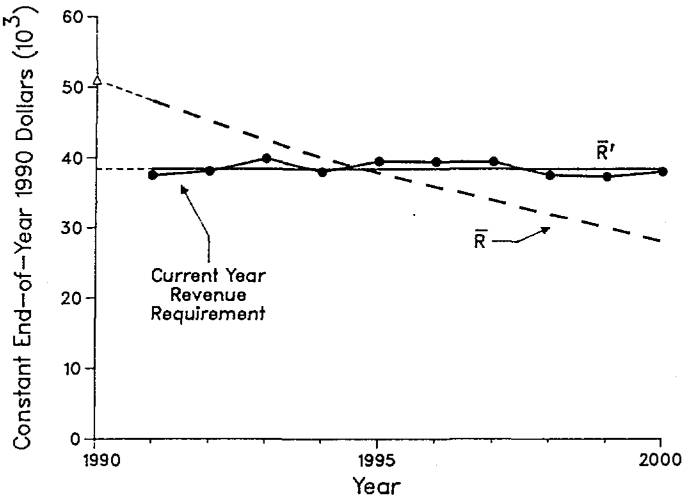

FIG. 6.6. Comparison of levelized costs in constant dollars.

6.2.2. Levelized bus bar cost

The basic concepts of cost levelization can be extended to calculate a levelized power generation or bus bar[4] cost, expressed in mills/kW·h, that is representative of the year-to-year variations in both costs and electric generation. This treatment of levelized costs neglects the complications introduced by income tax obligations, special tax preference allowances, and other specific tax or financial accounting laws which may be important considerations for utilities in some countries (e.g. investor-owned utilities in the USA). The effects of some of these considerations on levelized cost calculations are discussed in Refs [1–3]. Based on the discussion and recommendations in the previous section, a constant dollar levelized cost approach is used to derive the expressions for calculating a levelized bus bar cost. This approach results in a cost that can be referenced to a particular year's buying power.

If a generation alternative produces E_t kW·h of electricity in year t, then the average cost of electricity in that year, b_t' (mills/kW·h), can be determined as follows:

$$b_t' = \frac{1000 \times R_t'}{E_t} \tag{6.12}$$

where R_t' is the constant dollar revenue requirement for the alternative in year t.

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[4] By convention, the bus bar cost for an alternative is defined as the ratio of total fixed and variable costs (in mills) to net electricity production (in kW·h); it does not normally include transmission or distribution costs.

The revenue requirement, R'_t, can therefore be expressed as a function of the generation, E_t, and the constant dollar bus bar cost, b'_t, by rearranging Eq. (6.12) such that

$$R'_t = \frac{1}{1000} b'_t \times E_t \tag{6.13}$$

If a uniform price for electricity, $\bar{b}'$, in mills/kW·h, is charged each year over the life of the alternative, then the present worth of its revenues:

$$\sum_{t=1}^{N} \frac{\bar{b}' \times E_t}{1000\,(1+i')^t} \tag{6.14}$$

would have to equal the sum of the present worths of the actual annual revenue requirements, R'_t. Therefore, based on Eq. (6.9), the constant dollar levelized bus bar cost, $\bar{b}'$ (mills/kW·h), can be determined:

$$\bar{b}' = 1000 \left[\frac{\displaystyle\sum_{t=1}^{N} \frac{R'_t}{(1+i')^t}}{\displaystyle\sum_{t=1}^{N} \frac{E_t}{(1+i')^t}} \right] \tag{6.15}$$

In terms of annual fixed and variable costs C'_t and V'_t, respectively, expressed in constant dollars, where

$$R'_t = C'_t + V'_t \tag{6.16}$$

the constant dollar levelized bus bar cost defined in Eq. (6.15) can be rewritten in the following expanded form:

$$\bar{b}' = 1000 \left[\frac{\displaystyle\sum_{t=1}^{N} \frac{C'_t}{(1+i')^t}}{\displaystyle\sum_{t=1}^{N} \frac{E_t}{(1+i')^t}} + \frac{\displaystyle\sum_{t=1}^{N} \frac{V'_t}{(1+i')^t}}{\displaystyle\sum_{t=1}^{N} \frac{E_t}{(1+i')^t}} \right] \tag{6.17}$$

Multiplying the numerator and denominator of each term on the right-hand side of Eq. (6.17) by the capital recovery factor CRF′, the constant dollar levelized bus bar cost in mills/kW·h, $\overline{b}'$, can be defined as the sum of the constant dollar levelized annual fixed cost, $\overline{C}'$, and the constant dollar levelized variable cost, $\overline{V}'$, divided by the levelized electric generation, $\overline{E}$ (kW·h):

$$\overline{b}' = 1000\left[\frac{\overline{C}'}{\overline{E}} + \frac{\overline{V}'}{\overline{E}}\right] \tag{6.18}$$

where

$$\overline{C}' = \mathrm{CRF}' \sum_{t=1}^{N} \frac{C_t'}{(1+i')^t} \tag{6.19}$$

$$\overline{V}' = \mathrm{CRF}' \sum_{t=1}^{N} \frac{V_t'}{(1+i')^t} \tag{6.20}$$

$$\overline{E} = \mathrm{CRF}' \sum_{t=1}^{N} \frac{E_t}{(1+i')^t} \tag{6.21}$$

and

$$\mathrm{CRF}' = \frac{i'(1+i')^N}{(1+i')^N - 1} \tag{6.22}$$

The first term in Eq. (6.18) is defined as the constant dollar levelized annual fixed bus bar cost (1000 × $\overline{C}'/\overline{E}$) and the second term is defined as the constant dollar levelized annual variable bus bar cost (1000 × $\overline{V}'/\overline{E}$).

The following subsections discuss in detail the three variables used to define the levelized bus bar cost: the levelized electric generation ($\overline{E}$), the levelized annual fixed cost ($\overline{C}'$), and the levelized annual variable cost ($\overline{V}'$).

6.2.2.1. Levelized electrical generation

The kilowatt-hours of electricity generated by an alternative in year t, E_t, is a function of its rated capacity P (kW) and its average capacity factor in that year, CF_t:

$$E_t = 8760 \times P \times CF_t \tag{6.23}$$

where the capacity factor CF_t is defined as the ratio of the number of kilowatt-hours actually generated in year t to the number that would be generated if the alternative operated at rated capacity the entire year (i.e. for 8760 hours). Substituting Eq. (6.23) for E_t in Eq. (6.21), the levelized electrical generation over the life of the alternative can be expressed as follows:

$$\bar{E} = 8760 \times P \times CRF' \sum_{t=1}^{N} \frac{CF_t}{(1+i')^t} \tag{6.24}$$

or, from the general definition of a constant dollar levelized quantity as expressed in Eq. (6.10),

$$\bar{E} = 8760 \times P \times \overline{CF} \tag{6.25}$$

where $\overline{CF}$ is defined as the levelized capacity factor:

$$\overline{CF} = CRF' \sum_{t=1}^{N} \frac{CF_t}{(1+i')^t} \tag{6.26}$$

6.2.2.2. Levelized annual fixed cost

As defined in Section 6.1, the fixed costs in year t, C_t', include the costs arising from the initial investment in a power generation alternative, namely, fixed investment charges, I_t', and (neglecting taxes and insurance) annual fixed charges to accommodate the fixed cost portion of annual fuel and O&M costs, FF_t' and FO_t', respectively:

$$C_t' = I_t' + FF_t' + FO_t' \tag{6.27}$$

When this definition of fixed costs is substituted for C'_t in Eq. (6.19) the levelized fixed cost $\overline{C}'$ can be defined in terms of these fixed cost components:

$$\overline{C}' = \overline{I}' + \overline{FF}' + \overline{FO}' \tag{6.28}$$

where $\overline{I}'$ represents the levelized fixed investment cost, $\overline{FF}'$ represents the levelized annual fixed fuel cost, and $\overline{FO}'$ represents the levelized annual fixed O&M cost.

6.2.2.3. Fixed investment costs

The annual fixed investment cost, I'_t, is proportional to the initial investment I'_0 (constant monetary amount/kW) in a generation alternative; the constant of proportionality in year t, ϕ_t, is called the fixed charge rate:

$$I'_t = I'_0 \times P \times \phi_t \tag{6.29}$$

where P is the capacity of the generation alternative in kW. From Eqs (6.19), (6.28) and (6.29), the levelized annual fixed investment cost, $\overline{I}'$, can be calculated as follows:

$$\overline{I}' = I'_0 \times P \times CRF' \sum_{t=1}^{N} \frac{\phi_t}{(1+i')^t} \tag{6.30}$$

or, utilizing the definition of a levelized cost (Eq. (6.10)),

$$\overline{I}' = I'_0 \times P \times \overline{\phi} \tag{6.31}$$

where $\overline{\phi}$ is defined as the levelized fixed charge rate. As described earlier in Section 6.1.1, in the absence of tax insurance complications, the fixed charge rate is just the sum of the annual charge for depreciation plus the rate of return.

Using the definition of a levelized bus bar cost (Eq. (6.18)) along with Eqs (6.25), (6.28) and (6.31), the constant dollar levelized annual fixed investment bus bar cost can be defined as follows:

$$\begin{array}{c}\text{Levelized annual fixed investment} \\ \text{bus bar cost}\end{array} = \frac{1000 \times I'_0 \times \overline{\phi}}{8760 \times \overline{CF}} \tag{6.32}$$

6.2.2.4. Fixed fuel costs

The contribution of annual fixed fuel costs, FF'_t, which may arise, for example, from nuclear fuel cycle investments or coal stockpiling, to the total constant dollar levelized annual fixed fuel bus bar cost can be calculated from Eqs (6.18), (6.25) and (6.28):

$$\text{Levelized annual fixed fuel bus bar cost} = \frac{1000 \times \overline{FF}'}{8760 \times P \times \overline{CF}} \tag{6.33}$$

where $\overline{FF}'$ is defined from Eq. (6.10):

$$\overline{FF}' = CRF' \sum_{t=1}^{N} \frac{FF'_t}{(1+i')^t} \tag{6.34}$$

6.2.2.5. Fixed O&M costs

If the annual fixed O&M costs, FO'_t, which are independent of the amount of electricity generated in year t, can be related to a base year value such that they escalate[5] at the constant annual (real) rate of e' over the life of the alternative, then

$$FO'_t = P \times FO'_0(1+e')^t \tag{6.35}$$

where FO'_0 (monetary amount/kW) is the base year fixed O&M cost and P is the capacity of the alternative in kilowatts. The levelized annual fixed O&M cost $\overline{FO}'$ is then defined from Eqs (6.19) and (6.27) as follows:

$$\overline{FO}' = P \times FO'_0 \times CRF' \sum_{t=1}^{N} k^t \tag{6.36}$$

where

$$k = \frac{1+e'}{1+i'} \tag{6.37}$$

The term

$$CRF' \sum_{t=1}^{N} k^t \tag{6.38}$$

[5] Cost escalation is discussed in Section 5.1.

is defined as the levelizing factor $\overline{L}$ which can be reduced to the following simplified form:

$$\overline{L} = CRF' \left| \frac{k(1-k^N)}{1-k} \right| \tag{6.39}$$

where k is defined by Eq. (6.37).

Using the levelizing factor, along with Eqs (6.18), (6.25), (6.28) and (6.36), the constant dollar levelized annual fixed O&M bus bar cost can be defined as follows:

$$\begin{array}{c}\text{Levelized annual fixed O\&M} \\ \text{bus bar cost}\end{array} = \frac{1000 \times FO_0' \times \overline{L}}{8760 \times \overline{CF}} \tag{6.40}$$

6.2.2.6. *Levelized annual variable costs*

The variable costs in year t, V_t', expressed in monetary amounts, consist of variable fuel costs, VF_t', plus variable O&M costs, VO_t':

$$V_t' = VF_t' + VO_t' \tag{6.41}$$

When this definition of the variable costs is substituted for V_t' in Eq. (6.20), the levelized variable cost $\overline{V}'$ can be defined in terms of these variable cost components:

$$\overline{V}' = \overline{VF}' + \overline{VO}' \tag{6.42}$$

where $\overline{VF}'$ represents the constant dollar levelized annual variable fuel cost and $\overline{VO}'$ represents the constant dollar levelized annual variable O&M cost. Both the variable fuel costs and variable O&M costs depend on the amount of annual electricity generation.

6.2.2.7. *Variable fuel costs*

The variable fuel costs incurred in year t, VF_t', are a function of the unit fuel cost f_t' (monetary amount/J) in year t, the heat rate H (J/kW·h) of the alternative, and the generation E_t (kW·h) in year t:

$$VF_t' = H \times f_t' \times E_t \tag{6.43}$$

Using this relationship, the levelized annual variable fuel cost $\overline{VF}'$ can be defined as follows:

$$\overline{VF}' = H \times CRF' \sum_{t=1}^{N} \frac{f_t' \times E_t}{(1+i')^t} \tag{6.44}$$

If the unit fuel cost f_t' escalates at the constant annual (real) rate of e' over the life of the alternative, then

$$f_t' = f_0'(1+e')^t \tag{6.45}$$

where f_0' (monetary amount/J) is the unit fuel cost at time zero. By substituting Eq. (6.45) for f_t' in Eq. (6.44), the constant dollar levelized annual fuel cost can be rewritten as follows:

$$\overline{VF}' = f_0' \times H \times CRF' \left[\sum_{t=1}^{N} k^t \times E_t \right] \tag{6.46}$$

where k is defined by Eq. (6.37). Then using Eqs (6.18), (6.23), (6.25) and (6.46), the constant dollar levelized annual variable fuel bus bar cost (mills/kW·h) can be defined (assuming constant annual real escalation):

$$\begin{array}{c}\text{Levelized annual variable fuel}\\ \text{bus bar cost}\end{array} = 1000 \times \frac{f_0' \times H}{\overline{CF}} \times CRF' \left[\sum_{t=1}^{N} k^t \times CF_t \right] \tag{6.47}$$

When the capacity factor of the generation alternative can be assumed to be constant over the life of the alternative (which implies that the kilowatt-hours of generation are constant), then the levelized annual variable fuel bus bar cost defined in Eq. (6.47) can be simplified as follows:

$$\begin{array}{c}\text{Levelized annual variable fuel}\\ \text{bus bar cost}\\ \text{(constant capacity factor)}\end{array} = 1000 \times f_0' \times H \times \overline{L} \tag{6.48}$$

where $\overline{L}$ is defined by Eq. (6.39).

6.2.2.8. Variable O&M costs

Similarly, if the variable O&M costs, which have a base year unit cost of V'_0, in mills/kW·h, escalate at the constant annual real rate of e′ (which may be different from that used for fuel or other cost escalation) over the life of the alternative, then

$$VO'_t = \frac{VO'_0(1+e')^t}{1000} \times E_t \tag{6.49}$$

and from Eqs (6.20) and (6.41),

$$\overline{VO}' = \frac{VO'_0}{1000} \times CRF' \sum_{t=1}^{N} k^t \times E_t \tag{6.50}$$

where k is defined by Eq. (6.37).

Therefore, from Eqs (6.18), (6.23) and (6.25), the constant dollar levelized annual variable O&M bus bar cost (in mills/kW·h) can be calculated:

$$\text{Levelized annual variable O\&M bus bar cost} = \frac{VO'_0}{\overline{CF}} \times CRF' \left[\sum_{t=1}^{N} k^t \times CF_t\right] \tag{6.51}$$

When a constant capacity factor can be assumed, Eq. (6.51) can be simplified as follows:

$$\text{Levelized annual variable O\&M bus bar cost (constant capacity factor)} = VO'_0 \times \overline{L} \tag{6.52}$$

Table 6.II summarizes the levelized annual cost formulas for calculating the constant dollar levelized bus bar cost for a power generation alternative. The formulas condense all the cost information associated with a particular alternative into a fictitious constant charge that can be compared with levelized cost charges calculated for different power generation alternatives. However, because the levelization procedure converts the monetary information into a single figure of merit, levelized cost comparisons are meaningful only when the alternatives compared have similar functions (e.g. a comparison between base load alternatives)

TABLE 6.II. SUMMARY OF FORMULAS FOR CALCULATING CONSTANT DOLLAR LEVELIZED ANNUAL BUS BAR COST*

Levelized cost component[a] (mills/kW·h)	Constant dollar levelized annual cost formula[b]	
	Variable capacity factor	Constant capacity factor
Levelized annual fixed investment cost	$\frac{1000 \times I'_0 \times \overline{\phi}}{8760 \times \overline{CF}}$	$\frac{1000 \times I'_0 \times \overline{\phi}}{8760 \times CF}$
Levelized annual fixed fuel cost	$\frac{1000 \times \overline{FF'}}{8760 \times P \times \overline{CF}}$	$\frac{1000 \times \overline{FF'}}{8760 \times P \times CF}$
Levelized annual fixed O&M cost	$\frac{1000 \times FO'_0}{8760 \times \overline{CF}} \times \overline{L}$	$\frac{1000 \times FO'_0}{8760 \times CF} \times \overline{L}$
Levelized annual variable fuel cost	$1000 \times \frac{f'_0 \times H}{\overline{CF}} \times CRF' \sum_{t=1}^{N} k^t \times CF_t$	$1000 \times f'_0 \times H \times \overline{L}$
Levelized annual variable O&M cost	$\frac{VO'_0}{\overline{CF}} \times CRF' \sum_{t=1}^{N} k^t \times CF_t$	$VO'_0 \times \overline{L}$

NOTES TO TABLE 6.II

* For convenience, a constant annual real escalation rate of e' has been assumed in all component cost formulas. This does not, however, imply that all costs must escalate at the same rate. By changing the value of k, different real escalation rates may be applied to each cost component (i.e. fuel costs, variable O&M costs and fixed O&M costs). If costs vary over time in an irregular fashion rather than escalating at a constant annual rate, the annual cost data must be used directly in Eq.(6.17). All costs in the formulas are in terms of constant dollars referenced to the beginning of plant startup.

[a] Levelized annual bus bar cost = levelized annual fixed investment cost + levelized annual fixed fuel cost + levelized annual fixed O&M cost + levelized annual variable fuel cost + levelized annual variable O&M cost.

[b] Variable definitions:

I'_0: initial investment in alternative (S/kW)

$\bar{\phi}$: levelized fixed charge rate

$\overline{CF}$: levelized capacity factor

f'_0: unit variable fuel cost at time zero (\$/J)

H: heat rate (J/kW·h)

CRF': capital recovery factor $= [i'(1+i')^N]/[(1+i')^N - 1]$

k $= (1+e')/(1+i')$

e': real price escalation rate

i': real discount rate

CF_t: capacity factor in year t

VO'_0: unit variable O&M cost at time zero (mills/kW·h)

$\overline{FF}'$: levelized fixed fuel cost (\$)

FO'_0: unit fixed O&M cost at time zero (\$/kW)

N: book life of alternative

$\bar{L}$: levelizing factor $= CRF'\ [k(1-k^N)/(1-k)]$

TABLE 6.III. ILLUSTRATIVE DATA FOR SAMPLE CALCULATION OF THE LEVELIZED BUS BAR COST FOR A 600 MW(e) COAL-FIRED POWER PLANT
(All costs referenced to beginning of plant startup)

Parameter	Conditions and assumptions
Book life of unit (a)	30
Plant heat rate (kJ/kW·h)	10 000
Plant capacity factor (constant) (%)	60
Real discount rate (%)	4
Plant capital cost ($/kW)	1 600
Real price escalation rates (%):	
Coal	2
Variable O&M	1
Fixed O&M	1
Fuel cost ($/$10^9$ J)	3.9
Variable O&M cost (mills/kW·h)	2.4
Fixed O&M cost ($/kW·a)	15.6

and provide an equivalent quality of service. Furthermore, the economic parameters used in a comparative analysis (e.g. escalation and discount rates) must be consistent.

6.2.3. Illustrative levelized bus bar cost calculation

As an example of how the equations detailed in Table 6.II can be applied to calculate a constant dollar levelized annual bus bar cost, consider a 600 MW(e) coal-fired power plant with operating and economic data as summarized in Table 6.III. All cost data shown in this table are in end-of-year dollars referenced to the beginning of plant operation. The plant is assumed to operate at a constant capacity factor over a 30 year period. In real terms, coal prices are expected to increase over the life of the plant at a faster rate than O&M costs.

Using the information in Table 6.III and the appropriate equations in Table 6.II (i.e. for constant capacity factor), the constant dollar levelized annual bus bar cost (mills/kW·h) can be calculated as follows:

$$\mathrm{CRF}' = \frac{0.04\,(1.04)^{30}}{(1.04)^{30} - 1} = 0.0578$$

$$k_{fuel} = \frac{1.02}{1.04} = 0.981$$

$$k_{O\&M} = \frac{1.01}{1.04} = 0.971$$

$$\bar{L}_{fuel} = 0.0578 \left[\frac{0.981\,(1-0.981^{30})}{1-0.981}\right] = 1.306$$

$$\bar{L}_{O\&M} = 0.0578 \left|\frac{0.971\,(1-0.971^{30})}{1-0.971}\right| = 1.135$$

(a) Levelized annual fixed investment cost

$$= \frac{1000 \times 1600 \times 0.0578}{8760 \times 0.6}$$

$$= 17.59 \text{ mills/kW}\cdot\text{h}$$

(b) Levelized annual variable fuel cost

$$= \frac{3.9 \times 10\,000}{1000} \times 1.306$$

$$= 50.93 \text{ mills/kW}\cdot\text{h}$$

(c) Levelized annual variable O&M cost = $2.4 \times 1.135 = 2.72$ mills/kW·h

(d) Levelized annual fixed O&M cost

$$= \frac{1000 \times 15.6}{8760 \times 0.6} \times 1.135$$

$$= 3.37 \text{ mills/kW}\cdot\text{h}$$

Therefore, the levelized annual bus bar cost (in constant dollars referenced to startup) = a + b + c + d = 17.59 + 50.93 + 2.72 + 3.37 = 74.61 mills/kW·h.

6.3. SOME FACTORS AFFECTING ENERGY PRODUCTION FROM THERMAL GENERATING UNITS WITHIN A SYSTEM

Many aspects of electrical generation studies require systematic consideration of factors affecting energy production from generating units. The introduction of new units into an existing system affects energy costs and the operating performance. New units function differently in the context of integrated versus isolated operations. As a result, evaluations based solely on plant lifetime levelized costs are usually inadequate to compare capacity expansion options. Furthermore, the groupings of 'base load', 'intermediate' and 'peaking' technologies are inadequate to characterize the effects of important energy production factors. These terms only roughly indicate energy production and dispatch conventions associated with broad categories of generating technologies. More detailed characterizations are required for accurate performance and cost simulations and for consistent comparisons of alternative technologies.

This section emphasizes considerations important for systems consisting of thermal generating units. Other factors in mixed hydro-thermal systems and predominantly hydroelectric systems are covered in Chapter 8.

6.3.1. Introduction

The object of this section is to introduce and discuss key factors that influence energy production from units integrated with electrical utility systems. Discussions focus on the nature of interactions and the implications for production cost, reliability and capacity expansion modelling. Some quantitative estimates for factors are provided as examples and guidelines for analysis. Simulations that incorporate the effects of energy production factors are described in subsequent sections in this chapter and other chapters in this guidebook.

The intention here is to provide a level of detail appropriate for production cost and expansion models, not the level of detail required for real-time models of dispatch and operation. Real-time operational models must deal with additional concerns such as network power flows, frequency and system stability, startup and shutdown of equipment, economic dispatch, and other dynamic factors. These factors can affect energy production of units in a system but tend to be more subtle in nature and are usually beyond the scope of production cost and capacity expansion simulations. The emphasis here is on factors with major impacts on actual and simulated energy production for units in a thermal generating system.

6.3.2. Factor definitions and discussions

The discussions below are organized into separate subsections that focus on each of the energy production factors, although the concepts and interactions between factors tend to overlap. A consistent treatment of these factors is important in evaluating intertechnology tradeoffs.

6.3.2.1. Capacity factor

The capacity factor[6] of a generating unit is a measure of energy generation that displays with a single parameter the integrated effects of all energy production

[6] In some IAEA publications, the parameter defined here as *capacity factor* is referred to as *load factor*. In this guidebook, however, the parameter *load factor* has another meaning (see Sections 4.4, 6.5.3 and the Glossary).

factors discussed in this section. This parameter is frequently used in simulations to determine variable O&M and fuel costs for units. It is defined as the total energy produced by a unit within a given time period (kW·h) divided by the product of unit capacity (kW) and the number of hours in the time period. Time periods ranging from days to years are used to reference capacity factors for different purposes:

$$\text{Capacity factor} = \frac{\text{Total energy produced in time period (kW·h)}}{\text{Unit capacity (kW)} \times \text{hours in time period}}$$

Capacity factors are often used as indicators of the generating mode for which units are designed. For example, the Electric Power Research Institute, Palo Alto, (EPRI) uses the following ranges of capacity factors to distinguish between base load, intermediate and peaking units [4]:

Type of operation	Typical ranges for capacity factors
Base load	50–70%
Intermediate	20–40%
Peaking	0–10%

Variations within the ranges depend on unit availability, relative economics and the characteristics of the utility system. Units with capacity factors falling between the specified limits exhibit characteristics of both types of operation.

Capacity factors do not necessarily provide indications of other important operational factors. Although the number of startups and the magnitude and duration of output from a unit are reflected in the capacity factor, they are not uniquely determined. For example, a 50% capacity factor could occur with non-stop operation at 50% of the maximum capacity, or with a full capacity output during 50% of the time. The latter case could also be achieved with a single startup at the beginning of the period and shutdown at the period's midpoint, or with frequent startups for short durations of production.

6.3.2.2. *Unit availability: forced outage rates, repair times, scheduled maintenance*

Unit availabilities are governed by a combination of factors that account for outages, repair and maintenance. These factors have a major influence on energy production, reliability and cost modelling for individual generating units, as described in Section 6.5. The relationships between outage and availability factors are specified in Eqs (6.53–6.63), based primarily on definitions applied by the North American Electric Reliability Council (NERC) [5] and EPRI [4]. The equations define outage rates and availabilities in terms of the annual durations in various states of operation or readiness. The effects of partial outages are incorporated in definitions of 'equivalent' rates and availabilities. Several important distinctions are made between the *forced outage rates* defined in this chapter for use in production cost and reliability modelling and the *unplanned outage rates* defined by EPRI.

The total period hours (PH) consist of: (a) service hours (SH) during which a generator actually supplies energy to the system, (b) scheduled outage hours (SOH) for maintenance, (c) forced outage hours (FOH) during which a unit is fully shut down, and (d) reserve shutdown hours (RSH) when a unit is not required to generate owing to the ability of lower-cost units to satisfy system loads. The sum of the components equals the total period hours:

$$\mathrm{PH} = \mathrm{SH} + \mathrm{SOH} + \mathrm{FOH} + \mathrm{RSH} \tag{6.53}$$

Service hours (SH) include the hours when a unit performs satisfactorily and the hours when a unit generates less energy than demanded owing to partial outages.

Scheduled maintenance periods are required annually for most types of generating units for routine servicing of plant equipment. In nuclear units, scheduled maintenance is often performed in conjunction with refuelling operations. For modelling purposes, these combined operations are often considered jointly under the heading of scheduled maintenance, and the durations of such planned outages are defined to include the time requirements for both operations. It is important, from the point of view of system reliability and system cost, to simulate the scheduling of maintenance accurately with respect to load cycles and the availability of other generating units. The overall objective in scheduling maintenance is to minimize adverse effects on costs and reliability while satisfying the unit downtime requirements.

Available hours (AH) include service hours (SH) and reserve shutdown hours (RSH):

$$\mathrm{AH} = \mathrm{SH} + \mathrm{RSH} \tag{6.54}$$

For partial outages the equivalent forced outage hours (EFOH) are defined by a weighted sum of outage durations and magnitudes for each event of capacity reductions:

$$\mathrm{EFOH} = \sum \big((\text{forced partial outage hours}) \times (\text{per-unit size of capacity reduction})\big) \tag{6.55}$$

The planned outage rate (POR) is defined by EPRI in reference to total period hours as [4]:

$$\text{POR} = \frac{\text{SOH}}{\text{PH}} \tag{6.56}$$

whereas the scheduled outage rate (SOR) is defined by NERC in reference to service and scheduled outage hours as [5]:

$$\text{SOR} = \frac{\text{SOH}}{\text{SH} + \text{SOH}} \tag{6.57}$$

The full forced outage rate (FOR) is defined by the following equation [5]:

$$\text{FOR} = \frac{\text{FOH}}{\text{SH} + \text{FOH}} \tag{6.58}$$

Similarly, the equivalent forced outage rate (EFOR) is defined in reference to service and forced outage hours as [5]:

$$\text{EFOR} = \frac{\text{FOH} + \text{EFOH}}{\text{SH} + \text{FOH}} \tag{6.59}$$

The EFOR differs from the definition for equivalent unplanned outage rate (EUOR) used by EPRI [4]:

$$\text{EUOR} = \frac{\text{FOH} + \text{EFOH}}{\text{PH} - \text{SOH}} \tag{6.60}$$

Using Eq. (6.53), Eq. (6.60) can be rewritten in the following form:

$$\text{EUOR} = \frac{\text{FOH} + \text{EFOH}}{\text{SH} + \text{FOH} + \text{RSH}} \tag{6.61}$$

The difference between EUOR (Eq. (6.61)) and EFOR (Eq. (6.59)) is that reserve shutdown hours are not included in the denominator for EFOR. EFOR therefore represents the probability that a unit will fail when called upon for service, whereas EUOR represents the probability that a unit will fail during a time period when it is not on scheduled maintenance. The definition for EFOR is generally the correct definition for use in conventional production cost and reliability simulations.

Equivalent average repair times (EART) are used in calculations of outage frequency and duration. The definition is:

$$\text{EART} = \frac{\text{FOH} + \text{EFOH}}{\text{number of full outages} + \sum \text{per-unit capacity reductions}} \tag{6.62}$$

Equation (6.63) uses the planned outage rate (POR) (Eq. (6.56)) and the equivalent forced outage rate (EFOR) (Eq. (6.59)) to determine the equivalent availability (EA) for the time period:

$$EA = (1 - POR) \times (1 - EFOR) \tag{6.63}$$

The definition for equivalent availability differs from EPRI's equivalent annual availability (EAA) which substitutes EUOR for EFOR in Eq. (6.63) and from NERC's equivalent availability factor (EAF), which is essentially defined as EAF = (AH–EFOH)/PH.

The equivalent availability represents a maximum capacity factor that can be achieved by a generating unit given the maintenance and forced outage characteristics.

The equivalent forced outage rate (Eq. (6.59)) is often referred to simply as the forced outage rate and is abbreviated to FOR. It should not be confused with the definition shown in Eq. (6.58) since partial outages have not been factored into that equation. It is important that partial outages be included in the FOR for most types of probabilistic production cost and reliability modelling. Most simulation methods use two-state representations of unit outages; units are only considered to be fully available or fully unavailable. The equivalent forced outage rate (Eq. (6.59)) translates partial outage characteristics into the appropriate value to represent a two-state outage rate. Simulation methods that model more than two states of unit operation use expanded definitions of outage rates to represent the probabilities of occurrence for various levels of partial outages.

While a separate definition is given for average repair times (Eq. (6.62)), the effects of repair times are also accounted for in FORs. It is important to distinguish FORs from failure frequencies: FORs represent the fraction of time that unit cannot generate if called upon; failure frequencies represent the probability of failure during any time when a unit is operating. Repair times do not affect failure frequencies but do influence FORs. Production costs and some reliability criteria can be adequately represented through calculations with FORs, but other reliability measures (such as outage frequency and duration) require the more specific indication of average repair times and failure frequencies for outages.

The following example demonstrates the relationships for a hypothetical generating unit. Suppose that, in a time period of 1000 hours, a 100 MW unit:

(a) Operates for a total of 620 hours (SH);
(b) Is available but not called on for 170 hours (RSH);
(c) Is scheduled for planned maintenance of 150 hours (SOH);
(d) Is forced to shut down completely twice for 60 total hours (FOH); and
(e) Must be derated once to 40% of maximum capacity (i.e. 60% reduction) for 50 hours and once to 50% capacity for 20 hours.

Equations (6.53) – (6.63) define the following values:

Period hours = 620 + 150 + 60 + 170 = 1000 h (from Eq. (6.53))

Available hours = 620 + 170 = 790 h (from Eq. (6.54))

Equivalent forced outage hours = (50 × (1−0.4)) + (20 × (1−0.5)) = 40 h (from Eq. (6.55))

Planned outage rate = 150/1000 = 0.150 (from Eq. (6.56))

Scheduled outage rate = 150/(620 + 150) = 0.195 (from Eq. (6.57))

Forced outage rate = 60/(620 + 60) = 0.088 (from Eq. (6.58))

Equivalent forced outage rate = (60 + 40)/(620 + 60) = 0.147 (from Eq. (6.59))

Equivalent unplanned outage rate = (60 + 40)/(1000 − 150) = 0.118 (from Eq. (6.60))

Equivalent average repair time = (60 + 40)/(2 + 0.6 + 0.5) = 32.258 h (from Eq. (6.62))

Equivalent availability = (1 − 0.150) (1 − 0.147) = 0.725 (from Eq. (6.63))

These factors are important in estimating energy production for generating units. Planned maintenance and equivalent forced outage rates determine the availability of a unit for dispatch; the equivalent availability defines a limiting factor for maximum energy generation. Thus, for the example outlined above, maximum energy production for the 1000 hour period would be:

100 MW × 0.725 × 1000 h = 72 500 MW·h

Actual generation for the period could be less dependent on load levels and the availability of other lower-cost generating units.

6.3.2.3. Unit blocking: heat rates and spinning reserve

Although generating units are typically capable of providing output over a continuous range of capacities, they are often subdivided into smaller blocks of capacity for simulation. One reason for this is the variation in unit efficiencies that occurs with changes in the levels of output. Since unit efficiencies affect fuel costs, they also influence the relative rankings of units and unit blockings for dispatch. A primary goal in dispatching units is to meet load requirements with the cheapest energy sources. When units are divided into smaller blocks of capacity, the dispatching sequence can account for changes in efficiencies and associated costs that occur over the ranges of unit loadings.

EPRI has assembled representative efficiency data for various categories and sizes of generating units [6]. Appendix G contains samples showing typical trends in average heat rates associated with alternative levels of output. The full load heat rates shown in Appendix G should not be confused with incremental heat rates, which indicate the incremental number of J/kW·h associated with a small increase in output (kW). When an incremental heat rate is defined for a larger increase in output, it is referred to as the average incremental heat rate. Incremental block heat rates have to be averaged with all preceding blocks to obtain the net heat rate (J/kW·h) for a specified loading level. Average heat rates, as shown in Appendix G, have already combined the incremental values at each level of operation.

To derive incremental heat rates from average heat rates, the following relationships are applied:

L_1 is the smaller per-unit load level (kW)
L_2 is the larger per-unit load level (kW)
H_1 is average heat rate associated with L_1 (J/kW·h)
H_2 is average heat rate associated with L_2 (J/kW·h)

Then

$$\begin{array}{l}\text{Average incremental heat rate}\\ \text{(between } L_1 \text{ and } L_2\text{)}\end{array} = \frac{(L_2 \times H_2) - (L_1 \times H_1)}{L_2 - L_1} \qquad (6.64)$$

Using the values in Appendix G as an example and the conversion factor of 4187 J/kcal, the incremental heat rate for increasing the output for a 100 MW coal unit from 25% (25 MW) to 100% (100 MW) is as follows:

Average incremental heat rate

$$= \frac{(100 \times 10^3 \text{ kW} \times 12.226 \times 10^6 \text{J/kW·h}) - (25 \times 10^3 \text{kW} \times 15.659 \times 10^6 \text{J/kW·h})}{(100 \times 10^3 \text{kW}) - (25 \times 10^3 \text{kW})}$$

$$= 11.081 \times 10^6 \text{J/kW·h}$$

Equation (6.64) can also be rearranged to derive average heat rates if the incremental heat rate, the loading points and one of the average heat rates are specified.

Unit blockings are used to approximate design trends and historical observations in unit heat rates. The estimation of production costs and energy allocations per generating unit is directly affected by the blocking assumptions. The choices of unit blockings depend on simulation capabilities as well as on variations in heat rates. Some production cost models only consider single blocks for each generating unit, while others allow three or more blockings per unit for more accurate representations. The implications of blocking assumptions become more apparent in the discussions that follow regarding spinning reserves and unit loading orders.

TABLE 6.IV. TYPICAL DYNAMIC CHARACTERISTICS OF GENERATING UNITS (from [7])

Type of generation	Fast spinning reserve capability: Available % of rating	Fast spinning reserve capability: Time required (s)	Maximum rate for sustained load changes	Starting time
Fossil steam	20	10	2–5%/min	Hours
Gas or oil	30	30		
Coal	15	10	2–5%/min	Hours
	20	30		
Nuclear steam (LWR)	8	10	$1\frac{1}{2}$–3%/min	Hours
	20	30		
Gas turbine:				
Heavy duty	100	5	20%/s	3–10 min
Aircraft derivative	100	5	20%/s	1–5 min
Hydro:				
High head	0	10	1%/s	1–5 min
Medium head	20	10	5%/s	3–5 min
Low head	100	10	10%/s	1–5 min

6.3.2.4. Spinning reserve

Spinning reserve refers to generating capacity that can be called on in a few seconds to supply power in the event of sudden load increases or unit failures. The turbine-generators for such reserve thermal units generally need to be spinning while on reserve since there are substantial time delays in bringing a unit up to full power from a cold start and synchronizing its output with the system grid. Hydroelectric units do not need to be spinning to provide emergency fast pickup. This capability can be considered 'equivalent spinning reserve'. Typical dynamic characteristics of modern generating units are shown in Table 6.IV.

Methods for modelling spinning reserve vary, as do the actual criteria used by utilities to govern the reserve. In the simplest approach, a fixed capacity is specified, regardless of system loads or the sizes of generating units. More elaborate criteria include weighted considerations for peak loads (possibly daily or seasonal peaks) and the capacity of the largest unit on line at any given time. These additional factors are intended to make spinning reserve requirements sensitive to the parameters that determine system reliability.

Methods for allocating spinning reserve to separate units in a system are not standardized. Assigning major portions of the lowest-cost generator(s) to spinning reserve will usually create significant increases in production costs since higher-cost units will be required to satisfy loads normally met by the lower-cost unit(s). At the same time, production costs can increase dramatically if only the high-priced units are allowed to satisfy spinning reserves. In this case, the low-cost units might not be dispatched during low system load conditions owing to forced commitments of the high-cost units. An additional complication occurs when startup costs are considered; sometimes it is less expensive to run a high-cost unit temporarily than to start up a low-cost unit [7]. Strategies to avoid these problems generally involve spreading the spinning reserve requirement across many units in the system. Simulations of spinning reserve are usually accomplished through modifications to the loading order (discussed in the next paragraph).

6.3.2.5. Loading order

Loading order refers to the relative rankings assigned to units and blocks of units to be dispatched. The goal in ranking units is to provide a dispatching order that minimizes generation costs while satisfying all operating constraints. Variable costs are important in the formation of this ranking. In this context, variable costs refer to variable O&M and fuel costs. Fixed O&M costs, which are grouped with variable costs for some purposes, are excluded since they are not directly influenced by unit loads.

Variable O&M costs are usually expressed in terms of $/kW·h, which are the appropriate units for ranking generating units. (Illustrative values for variable O&M costs are given in Appendix H.) Occasionally, variable cost components are related only to the duration of generation. These are expressed as $/h and must be converted into $/kW·h for the purpose of ranking units for dispatch. The conversion is non-trivial since estimates on the average loading points (capacities in kW) for units are required before simulation. Other types of variable costs, such as startup costs, may also require some conversions or assumptions in order to be combined with loading order assumptions. Startup costs are likely to be expressed in terms of J/startup, which must be converted to $/startup for dispatch optimization.

Fuel costs constitute the major portion of variable costs used in ranking units for dispatch. To calculate this component, fuel prices and the unit heat rates must be known or estimated. Reasonably accurate estimates of fuel prices can often be obtained for near-term projections, but the specification of heat rates is more difficult. Heat rates depend on unit output levels, which are determined by dispatch priorities. Dispatch priorities, in turn, are influenced by assumptions regarding heat rates.

Unit blockings help to separate the interrelated effects of heat rates and loading orders. The capacity of a unit can be segmented into blocks of capacity which are assigned fixed heat rates over the restricted range of output. Increasing the number of blocks generally improves modelling accuracy but increases the complexity and computational requirements of simulation.

The following examples[7] show how unit blocking affects loading orders for two hypothetical units:

Assume the following characteristics:

	Unit A	Unit B
Unit capacity	100 MW	200 MW
Average heat rate at 50% output	13.15 MJ/kW·h	13.52 MJ/kW·h
Average heat rate at 100% output	12.23 MJ/kW·h	10.51 MJ/kW·h
Fuel price	$\$955/10^6$ MJ	$\$955/10^6$ MJ
Variable O&M costs	3.0 mills/kW·h	3.0 mills/kW·h

With no blocking assumed for units, the full-load variable costs combine variable O&M costs and fuel costs as follows:

Unit A variable cost

$$= (3.0 \text{ mills/kW·h}) + (\$955/10^6 \text{MJ} \times 1000 \text{ mills/\$} \times 12.23 \text{ MJ/kW·h})$$
$$= 14.7 \text{ mills/kW·h}$$

Unit B variable cost

$$= (3.0 \text{ mills/kW·h}) + (\$955/10^6 \text{MJ} \times 1000 \text{ mills/\$} \times 10.51 \text{ MJ/kW·h})$$
$$= 13.0 \text{ mills/kW·h}$$

Given no other restrictions, Unit B would be loaded before Unit A owing to lower variable energy costs.

If the units are blocked into two segments, each with 50% maximum capacity, the variable costs for each block are as follows:

Unit A

Block 1 average incremental variable cost (50% output; 50 MW) $= 3.0 + 955 \times 10^{-6} \times 1000 \times 13.15 = 15.6$ mills/kW·h

[7] These examples use hypothetical unit characteristics to demonstrate some general principles or possibilities. The heat rates and fuel costs should not be interpreted as representative values. Refer to the appendices for illustrative values.

Unit A
Block 2 average incremental
variable cost[8] $= 3.0 + 955 \times 10^{-6} \times 1000 \times 11.31 = 13.8$ mills/kW·h
(100% output; 100 MW)

Unit A
Total unit variable cost $= 3.0 + 955 \times 10^{-6} \times 1000 \times 12.23 = 14.7$ mills/kW·h
(100% output; 100 MW)

Unit B
Block 1 average incremental
variable cost $= 3.0 + 955 \times 10^{-6} \times 1000 \times 13.52 = 15.9$ mills/kW·h
(50% output; 100 MW)

Unit B
Block 2 average incremental
variable cost[8] $= 3.0 + 955 \times 10^{-6} \times 1000 \times 7.50 = 10.2$ mills/kW·h
(100% output; 200 MW)

Unit B
Total unit variable cost $= 3.0 + 955 \times 10^{-6} \times 1000 \times 10.51 = 13.0$ mills/kW·h
(100% output; 200 MW)

Now the assignment of loading orders becomes more difficult. The second blocks of each unit have lower variable costs than their respective first blocks, yet these blocks cannot be loaded unless the first blocks are already dispatched. Furthermore, the example shows that the assignment of loading orders may depend on system load levels.

If load requirements for these two units totalled 200 MW or more, the best strategy would be to dispatch all of Unit B and then use Unit A to satisfy any remainder. Incremental variable costs are very low for the second block of Unit B and it is cost effective to bring on the higher-cost first block in order to take advantage of these low costs. If, however, the system load requirements for these two units were on the order of 100 MW, the strategy would change. Loading both blocks of Unit A would provide an average variable cost of 14.7 mills/kW·h which is lower than the 15.9 mills/kW·h that could be obtained from the first 100 MW (Block 1) of Unit B. For the smaller system load levels, it does not matter that Block 2 of Unit B has the lowest incremental energy costs because Block 1 has enough capacity to satisfy those loads and must be dispatched before Block 2.

Spinning reserve requirements (discussed earlier) create additional constraints for loading order assignments. To reduce the likelihood of system failure in the event of sudden outages or load fluctuations, a spinning reserve criterion (usually given in MW) is established. Fractions of generator output are withheld from units

[8] Incremental heat rates for the second blocks of capacity are derived from Eq. (6.64).

on line in order to satisfy the reserve criterion. The allocation of capacity held in reserve affects loading order assignments, unit generation and energy costs.

To illustrate the importance of spinning reserve treatments, the previous example with two units, A and B, can be used. If some amount of spinning reserve (e.g. 20 MW) was required from these units, there are many alternatives for allocating the requirements, and their cost impacts may depend on system load levels. Assigning all of the spinning reserve to Unit B precludes the sole use of Unit A if the loads are low. An 80 MW load, which would normally be served by Unit A (leaving 20 MW to satisfy the reserve requirement), would instead require that Unit B be brought on line in spite of higher variable costs. In the reverse situation, assigning all the spinning reserve requirements to Unit A would create higher costs than necessary for other load conditions. A system load of 180 MW would typically be generated from Unit B but Unit A would have to be operated, at least at some level, in order to meet the spinning reserve criterion.

Factors other than variable costs, unit blocking and spinning reserve also affect loading orders. The rate at which units can be powered up or down influences the selection of units to be dispatched. Some types of unit are physically restricted, for design reasons, from following rapid changes in system loads. For these units, other 'peaking' units must be kept on line even though variable costs may increase substantially.

Environmental constraints, in some cases, require modifications to the least-cost loading order. For example, air emission standards may lead to cases where the dispatch or fuelling options for some units depend on the disposition of other nearby units. Fuel switching (i.e. to low-sulphur fuels) affects variable costs and the relative attractiveness of a unit for dispatch.

These and other system-dependent factors are important in loading order assignments. Loading orders based on variable costs provide the initial guidelines for dispatch, but they must be modified or overridden to account for other factors. Modelling approaches depend on utility system practices as well as simulation capabilities.

6.3.2.6. System loads

System load magnitudes and rates of change are important factors in determining energy production for units in a system. The position of a specific unit in the loading order determines how quickly it will be called upon in relation to the other units. The actual energy production of a unit depends, however, on the occurrence of loads large enough to reach or exceed the loading point of that unit. If a unit is loaded late in the loading sequence and system loads happen to be low in a given time period, then generation may be low even while availability is high. On the other hand, it may be that unit outages (planned and forced), load fluctuations, unit blockings and spinning reserve could produce high demands for even the high-cost units. Potential interactions between system loads, spinning reserves and unit blockings have been identified in earlier discussions according to their effect on unit energy production and costs.

Scheduled maintenance, forced outages and ramp-rate restrictions for units loaded early in a sequence can create energy demands for units that would normally not be reached in the loading order. The primary effects of forced outages are obvious. Energy that would have been generated by units forced out of service must be supplied by units appearing later in the loading sequence. The effects of scheduled maintenance are similar in this respect. Optimal strategies for scheduling maintenance are directly linked with load estimates and unit characteristics so that planned outages can be scheduled to minimize cost and reliability impacts. The approaches used to facilitate the goals of maintenance scheduling are usually sensitive to system load and generating unit characteristics. The effects of changing load assumptions can alter the maintenance schedule and significantly affect generation requirements for each unit in a system.

Chronological load representations are required for certain aspects of production cost and reliability modelling. For example, short-term fluctuations affect the distribution of generation between units since some units are unable to follow rapid load changes, while others are required to remain in service even though their costs may be higher and even though the lower-cost units may not be completely committed. The actual time sequence of load variations is needed to simulate these effects on unit energy production allocations. The same applies to representations of hydroelectric plants (including storage and pondage hydroelectric plants), intermittent sources (such as wind and solar) and storage technologies. The availability of generation from these sources is not as randomly distributed as it tends to be for conventional generating units.

The effects of some factors can be modelled with load duration curves, which contrast with chronological loads in that they portray only the percentage of times particular load levels occur or are exceeded, but not the sequence of occurrence. Load duration curves reduce the computational and data storage requirements for many types of calculation. Discussions in subsequent sections show how load duration curves are used in probabilistic calculations to determine the effects of forced outages on energy production from specific generating units and on system reliability.

6.3.3. Summary

Factors described in this section are not necessarily treated in all production cost and expansion planning models currently in use. In practice, however, they can all affect the energy production and cost effectiveness of units in a generating system. The complex interactions between energy production factors make it important to apply integrated systems analysis techniques to determine impacts and tradeoffs consistently. (Specific methods that have been developed and refined for dealing with the major factors affecting energy production for units within a utility system are discussed below.)

6.4. UNCERTAINTY ANALYSIS

Major uncertainties are often encountered in evaluations of alternative generating technologies, and they can significantly reduce confidence in technology choices based on single-point estimates of uncertain parameters. Many of the uncertainties are unavoidable in generation planning studies because long-term projections are required for designs, resources, costs and operations. Basic factors affecting energy production and costs of generating units (described in Section 6.3) are all examples of potential sources of uncertainty in technology evaluations. While these uncertainties tend to be especially acute for advanced technologies, they are also significant for conventional or proven designs. This section briefly reviews different approaches for decision-making under uncertainty and presents a probabilistic approach for treating uncertainties in generating technology costs and characteristics.

6.4.1. Decisions under uncertainty

Decisions to be made as a result of generating system analysis have characteristics not unlike those described in classical decision theory. In particular, almost all decisions involve a comparison of alternatives under some degree of uncertainty. Different methods have been developed to account for uncertainty, and reasonable decision rules for various circumstances have been established [8–10].

The problem characteristics are best illustrated by a simple example in Ref. [8][9]. A reservoir used for both irrigation and flood protection is full at the beginning of the flood season. For this illustration it is assumed that if a flood occurs its consequences are known, i.e. the uncertainty is whether or not a flood occurs, not what are the consequences of the flood. The decision to be made at the beginning of the flood season is whether to spill one-third of the water in the reservoir, two-thirds of the water, or all the water. The possible consequences for each state of the system are shown in Table 6.V. The benefits of having sufficient water for irrigation and harvest must be balanced against the risks of flood damage.

The net result in terms of cost in Table 6.V is obtained by subtracting the flood damage from the harvest value. Using the monetary consequences as a decision criterion, the decision to spill all is inferior to the other two decisions, independent of the probability of flood. The choice between the other two alternatives is more difficult. If a flood occurs, two-thirds of the water should be spilled; if a flood does not occur, only one-third of the water should be spilled. Thus, the criterion that should be used for the basis of this decision is not obvious.

A number of different criteria, each having a reasonable rationale, have been developed. Each represents a different decision-making attitude, often resulting

[9] Adapted from Section 15 of Ref. [8], Decision Rules under Uncertainty, by R. Dorfman, pp. 360–392.

TABLE 6.V. MONETARY CONSEQUENCES OF ALTERNATIVE DECISIONS ON RESERVOIR OPERATION (in 10^3 \$)

Decision	Flood			No flood		
	Harvest value	Flood damage	Net result	Harvest value	Flood damage	Net result
Spill one-third	380	250	130	400	0	400
Spill two-thirds	240	100	140	260	0	260
Spill all	80	0	80	80	0	80

in different 'optimal' strategies, depending on the choice of decision criteria. Some possible criteria, greatly simplified, are outlined in the next paragraphs. No attempt is made here to list all theoretical shortcomings associated with the alternative decision criteria presented. Each has some justification and some limitations. The fact that the choice of decision criterion can lead to entirely different strategies indicates that decision-making under uncertainty deserves some attention in important generation planning studies. The literature includes more complete discussions of the advantages and disadvantages of each approach [8–10].

Maximin returns: One possible approach is to maximize the minimum amount of monetary returns. That is, spilling one-third could result in a return of only \$130 000, while choosing the two-thirds spill option guarantees at least \$140 000 return. Thus, under the maximin returns criterion for decision, the spill two-thirds decision should be made. This decision criterion is usually thought of as pessimistic because the decision is based on the worst possible outcomes without regard for the probabilities of favourable outcomes.

Maximax returns: Another approach quite different in philosophy from maximin returns is to maximize the maximum amount of monetary returns. In this case, spilling one-third could result in a \$400 000 return, while spilling two-thirds could only result in a \$260 000 payoff. Thus, under the maximax returns criterion for decision, the spill one-third decision should be made. The decision criterion is considered optimistic, because only the best possible outcomes from each decision are used.

Minimax regret: It may be more natural for decision-makers to think of opportunity costs (or losses) rather than yields [9]. Regret is defined as the difference between the payoff that would have resulted from the best decision for a particular outcome (flood or no flood) and the payoff that does result from each individual decision. Thus, from Table 6.VI, the regret from spilling one-third if a flood occurs is \$10 000 (\$140 000 – \$130 000). The levels of regret for the other decisions are also indicated in Table 6.VI. The minimax regret criterion is to choose

TABLE 6.VI. REGRET TABLE FOR THE RESERVOIR DECISION (in 10^3 \$)

Decision	Regret		Maximum regret	Minimum of maximum regret
	Flood	No flood		
Spill one-third	10	0	10	10
Spill two-thirds	0	140	140	
Spill all	60	320	260	

TABLE 6.VII. EXPECTED MONETARY VALUE FOR THE RESERVOIR DECISION (in 10^3 \$)

Decision	Returns		Expected monetary value
	Flood	No flood	
Spill one-third	130	400	292
Spill two-thirds	140	260	212
Spill all	80	80	80
Probability of occurrence	0.4	0.6	

the alternative that minimizes the maximum regret, i.e. the option with the maximum possible regret as small as possible. In the example, the decision to spill one-third is therefore the best.

Probability: It seems reasonable that the basis for decision should incorporate the relative likelihoods of the possible outcomes, but it is not adequate to simply choose the action for which the highest probability outcome is best. If it were known that the probability of flood, based on historical data, was 0.4, and therefore the probability of no flood is 0.6, the best decision is still not obvious. The following criteria use these probabilities to determine the best course of action.

Expected value: By multiplying the probabilities by the consequences and summing for each possible decision, the expected monetary value for each decision can be determined (Table 6.VII). The expected value criterion is to pick the alternative that maximizes the probability-weighted returns. In this case, spill one-third is the best decision. However, strict application of the expected value criterion does not account for the risk associated with each alternative.

That is, if the decision-maker just looks at the expected monetary value in Table 6.VII, it is not known whether the \$292 000 results from a 0.4 chance of \$130 000 and a 0.6 chance of \$400 000 or a 0.9 chance of −\$10 000 (a loss) and a 0.1 chance of \$3 010 000. Such a difference in possible outcomes could easily affect a decision alternative's overall desirability. Thus, the expected value criterion is sometimes considered inappropriate because of its insensitivity to risk of undesirable outcomes.

Utility: Some decision-makers attempt to avoid risky situations, especially if significant losses are possible. Decision analysis using utility theory is based on the assumption that the expected value of utility (a measure of satisfaction) is the appropriate decision criterion. That is, a utility value for each possible consequence is determined and the probabilities are used to weight the utilities rather than the physical consequences (dollars in the reservoir problem). The utility values are assessed such that the decision-maker's risk attitudes are automatically incorporated in the utility scale. If the decision-maker bases decisions strictly on expected value, the expected utility approach will yield the same result as the expected value approach. Utility theory has been widely used on problems involving multiple conflicting objectives in which achievement of some objectives in monetary terms is difficult to measure [10].

All the above methods for decision-making under uncertainty have advantages and disadvantages for particular applications. A probabilistic approach for detailed analysis of a generating system problem is outlined below. The example indicates how easily simple concepts can become difficult to apply. Yet, for important decisions in generation planning, the benefit of having the information on the uncertainty associated with various possible outcomes justifies at least some effort to incorporate uncertainty analysis in study.

6.4.2. Example of probabilistic uncertainty analysis

Probabilistic methods can help to gauge the combined effects of multiple uncertainties in cost and performance estimates. The STATS (Stochastic Analysis of Technical Systems) model [11], an analysis method based on Monte Carlo simulations, is presented here with hypothetical examples to demonstrate one approach for treating uncertainties and correlations between cost and performance components. The approach has the capacity to provide improvements in technology comparisons over conventional levelized cost methods. System integration factors can be treated, although not so consistently as in a detailed production cost analysis or system expansion study. Nevertheless, the additional information developed in uncertainty analysis is useful for considering relative risks and benefits of technology options.

Uncertainties are encountered in nearly all aspects of technology evaluations. Problems with uncertainties are often acknowledged, but the treatments are varied and the quantitative implications are frequently not discussed. In some situations sensitivity analyses are used as a means to quantify these implications. Input assumptions can be altered in deterministic calculations to determine possible ranges of outcomes. However, neither the relative likelihood of possible outcomes nor the combined effects of multiple uncertainties are obtained.

Although they are more difficult to develop than cost ranges, the relative probabilities of potential cost outcomes are more useful. One could imagine that the lowest possible costs for a technology would only be obtained with the simultaneous occurrence of many favourable economic trends and engineering developments. Certainly these minimum costs are possible, but they are less likely to be obtained than the higher costs that would arise from various combinations of less favourable events. The more detailed cost-versus-probability functions are important for R&D investment decisions and other risk-dependent technology selection processes.

The STATS model is used later in this section to demonstrate the major concepts and considerations embedded in probabilistic methods applied to technology comparisons. Other approaches to similar problems have been proposed or applied [12–15]. References to these studies are provided, although a comprehensive survey of approaches is not given. Instead, hypothetical examples are used to demonstrate how probabilistic methods can help in the analysis.

In broad terms, uncertainty analysis requires cost components and performance factors to be represented by probabilistic value distributions. Relationships between component costs or other driving factors are modelled through correlations. Relationships within a single technology or between components of many technologies can be represented. STATS performs a large number of Monte Carlo simulations to obtain distributions of total energy costs and comparative costs for the technologies under investigation.

Figure 6.7 shows graphically the analysis for two technologies. Cost and performance components are used to construct probabilistic estimates of total energy costs. Probability density functions define relationships between the relative likelihood and the range of possible outcomes for variable components. Probability distributions represent the cumulative probabilities of occurrence for variables. These functions can be examined separately for each technology or they can be combined to show relative probabilities of cost differences. The cost difference distribution is capable of displaying the effects of correlated cost components between technologies that cannot be recognized in the separate cost distributions. In reduced form the comparisons can be expressed as the relative likelihood (simple percentages) that each technology will yield lower energy costs. The disadvantage of this simpler expression is that the magnitude of potential cost differences is not portrayed.

Major attention has been given to representations of correlated variables. As an example of these, if capital costs for subsystems, such as coal-handling facilities or boilers, are defined as problem components for each of two generating technologies, then the contribution of uncertainty from these components must

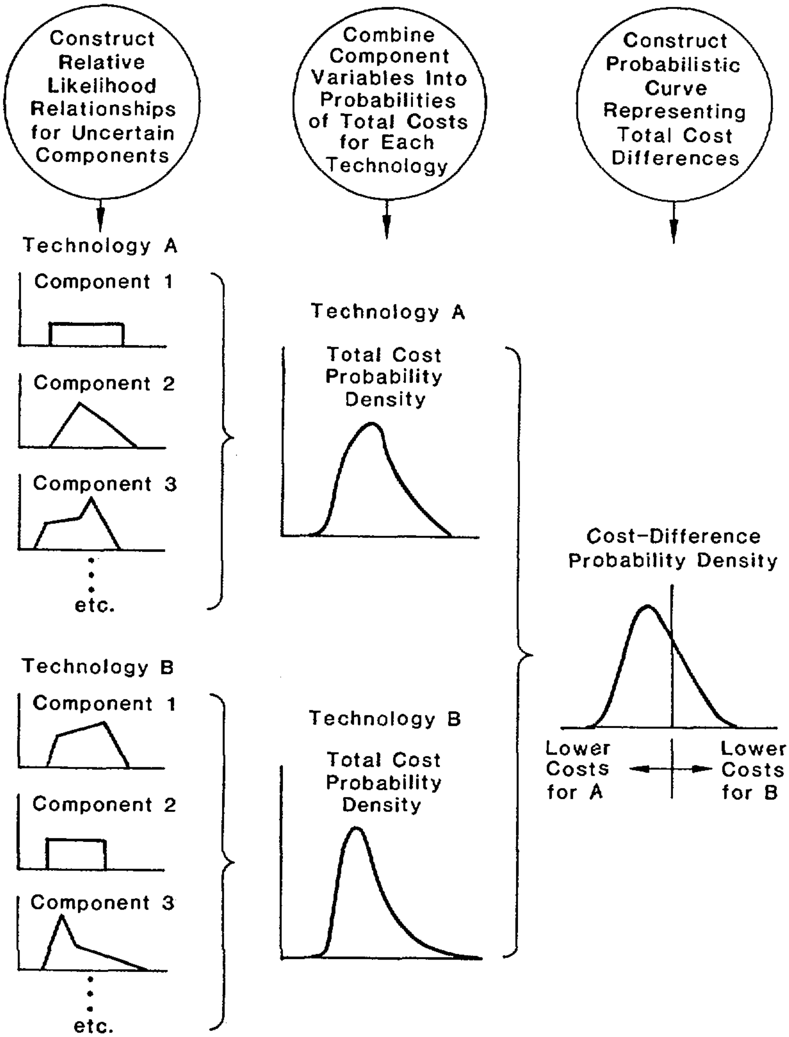


FIG. 6.7. Overview of probabilistic uncertainty analysis.

be correlated. The component costs are still uncertain, but when they are high for one technology they would also be high for another that uses the same or similar components. More subtle correlations can be traced to secondary factors in other components. For example, costs for coal-handling equipment and oil-fired boilers may be partially correlated owing to common inputs such as labour, materials and transport.

The hypothetical examples presented in Section 6.4.4 were developed primarily for testing purposes. While the problems are sufficiently realistic to highlight sensitive variables and component relationships, they have not been researched thoroughly enough to support any choices regarding the technology alternatives. Results have been presented as probability density functions that portray the relative likelihood of given cost differences between two technologies. These distributions are also condensed into the less detailed probabilities that one technology will be the lower-cost alternative.

Probabilistic approaches provide improvements over some of the deterministic or fixed-point analyses. Limitations are likely to be encountered when attempting to treat system integration effects in a consistent framework. The level of detail possible for system modelling is restricted by the requirement for large numbers of Monte Carlo trials. The probabilistic approach to uncertainty analysis precludes the use of some desirable features of production cost, reliability, and expansion optimization models. As such, the uncertainty analysis is best suited for side-by-side use with deterministic models that deal with some of the more detailed system integration effects.

The remainder of this section describes the STATS model in greater detail and presents several examples of applications. The model description defines input requirements, algorithm logic and output options. The hypothetical examples compare two advanced coal combustion technologies. Variations illustrate the potential sensitivity of technology comparisons to the problem interpretation, correlation assumptions and uncertainty estimates.

6.4.3. Approach

Uncertainty analyses of electrical generating technologies require both economic and technical forecasts. Technical inputs describe in detail the construction requirements and operational characteristics of the project. For example, electricity generating facilities would be described in terms of construction materials, labour requirements, conversion efficiency, etc. Economic factors link the technical description with parameters such as inflation rates and costs for capital and labour.

The level of detail to be treated in uncertainty analyses depends largely on the available data. It should be clear that an overwhelming number of factors can influence the performance and costs of a generating technology. Technical performance is affected by design, construction and operational considerations all of which have subcomponent uncertainties. Cost factors depend on fuel, labour, transport and capital costs. Contributing to the uncertainty of these factors are influences from general economic conditions, resource availability, and external regulation. Other uncertainties arise from the integration of units with a utility system.

The first task in defining the uncertainty problem is to determine the level of detail for which the factors can be adequately characterized from data or expert opinion. Greater detail is desired for accuracy, while the appropriate literature may only be related to composite uncertainties (e.g. uncertainties for combined turbine-generator costs rather than for the individual components). There may be some influencing factors beyond the scope of a probabilistic analysis, such as major political trends or international relationships that could in the long run affect technology development, resource availability, etc. The uncertainty model then becomes a tool for examining probabilistic events within the context of broader scenarios or hypotheses.

Each analysis must be tailored to specific applications and data limitations. These preclude the use of standard problem formulations, and sample problems are used instead in the following sections to illustrate the general approach.

6.4.3.1. The STATS model

The STATS model makes use of probabilistic representations for cost components and other variables. Figure 6.8 illustrates the sequence of calculations that generate composite costs from component distributions. First, the relative probability-density functions are integrated into cumulative distributions that associate probabilities (between zero and one) with ranges of possible values. Next, random numbers between zero and one are chosen and mapped against the variable distributions to assign specific cost and performance values to each problem variable, weighted by the original probability densities. Correlations are introduced by applying single random drawings to more than one variable at prespecified intervals throughout the simulations.

Once the values of problem variables have been assigned, the composite energy costs for each technology are calculated. Cost differences are also recorded for each trial in order to preserve the effects of correlated variables. (A trial consists of one complete set of drawings for all problem variables and the subsequent determination of total energy costs and cost differences.) The sequence of calculations is repeated in a Monte Carlo simulation by selecting new random numbers. Results from all the trials are used to construct probabilistic representations of total technology costs and cost differences.

Monte Carlo simulations are used instead of other analytical methods (closed-form solutions) to maintain flexibility in representations for variable distributions and correlations. Uncertainty distributions of many different shapes can be treated, and any degree of correlation between variables can be modelled. Correlation coefficients are calculated for individual cost components, total energy costs for each technology, and cost-difference distributions. Sample means and variances can be compared with actual values to verify that the representative sampling was obtained.

6.4.3.2. Uncertainty distributions

The task of developing a probability-density function may seem especially difficult if the goal is to determine precisely the 'true' distribution. However, a more reasonable goal is to use the best judgement and data available to approximate uncertainty estimates. In that case the precise shapes of the uncertainty input curves are not of overriding importance, i.e. the normal, beta and triangular distributions give roughly the same results, provided that the ranges and mean values of costs and performance are in close agreement.

The STATS model is currently designed to accommodate uniform, triangular or five-point probability-density functions. A uniform (flat) distribution is specified by the range of variation. Sample values for uniform distributions have equal probabilities of occurrence over the designated range of uncertainty. This option is most useful when the uncertainty data are very limited, for example when there is little information to structure the distribution or when the distribution cannot be agreed upon.

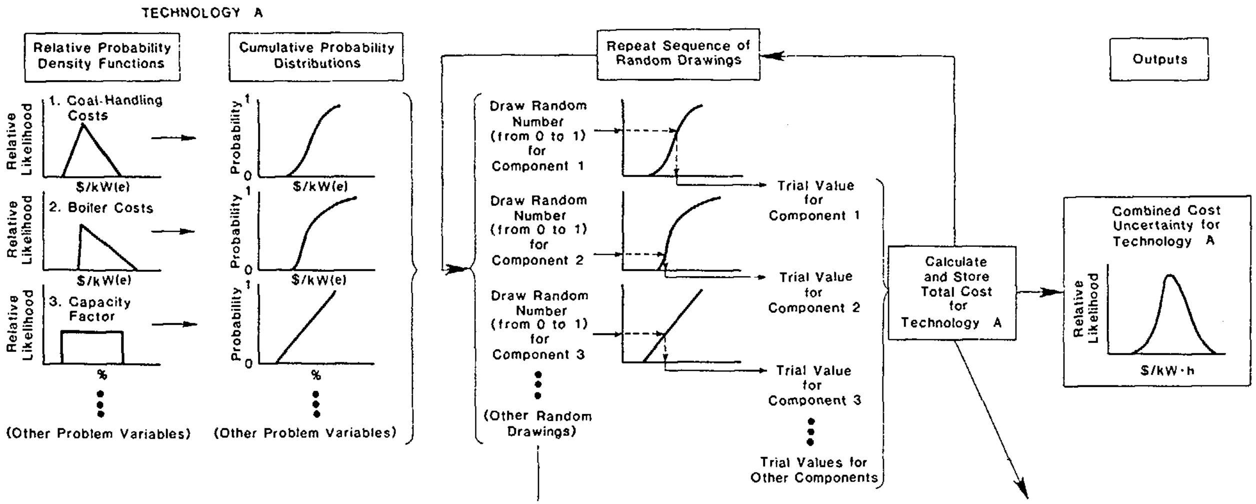
When the most likely value, or mode, of a density function can be specified, in addition to the range of possible outcomes, a triangular representation can be constructed. If more detailed information is available, a five-point density function can be adopted. Two of the five points are assigned to the upper and lower bounds of uncertainty. The remaining three points may be assigned relative probability values in order to approximate various skewed or bimodal functions. The use of triangular density functions (rather than more sophisticated forms) simplifies the initial parameter uncertainty characteristics. Judgemental approximations of modes and likely ranges are easier to obtain from qualified individuals than precise distribution shapes. Many sources have proposed or applied various methods for constructing uncertainty estimates [12–17]. Although difficulties exist, methods and data sources appear to be available to support preliminary estimates of uncertainty relationships.

With minor modifications, the uncertainty model can make use of other types of distributions, such as normal and beta probability-density functions. However, the data required to provide any improvement over simpler representations are usually not available.

6.4.3.3. Correlation representations

Problem variables can be conveniently correlated in the Monte Carlo simulations. Relationships can be modelled for variables within a technology or between variables of two separate technologies. The degree of correlation is controllable and can range from completely dependent relationships to uncorrelated uncertainties. Partial correlations are obtained by specifying direct correlations at specified intervals in the Monte Carlo trials or by constructing composite variables from combinations of independent and totally correlated distributions. The latter method introduces a correlated component and a random element of partially correlated variables.

Disaggregation of variables into their most basic components can help simplify the treatment of correlations. For example, construction costs of coal-handling


TECHNOLOGY A
Relative Probability Density Functions
Cumulative Probability Distributions
Repeat Sequence of Random Drawings
Outputs
Relative Likelihood
1. Coal-Handling Costs
$/kW(e)
2. Boiler Costs
$/kW(e)
3. Capacity Factor
%
(Other Problem Variables)
Probability
1
0
$/kW(e)
$/kW(e)
%
(Other Problem Variables)
Draw Random Number (from 0 to 1) for Component 1
Draw Random Number (from 0 to 1) for Component 2
Draw Random Number (from 0 to 1) for Component 3
(Other Random Drawings)
Trial Value for Component 1
Trial Value for Component 2
Trial Value for Component 3
Trial Values for Other Components
Calculate and Store Total Cost for Technology A
Combined Cost Uncertainty for Technology A
Relative Likelihood
$/kW·h

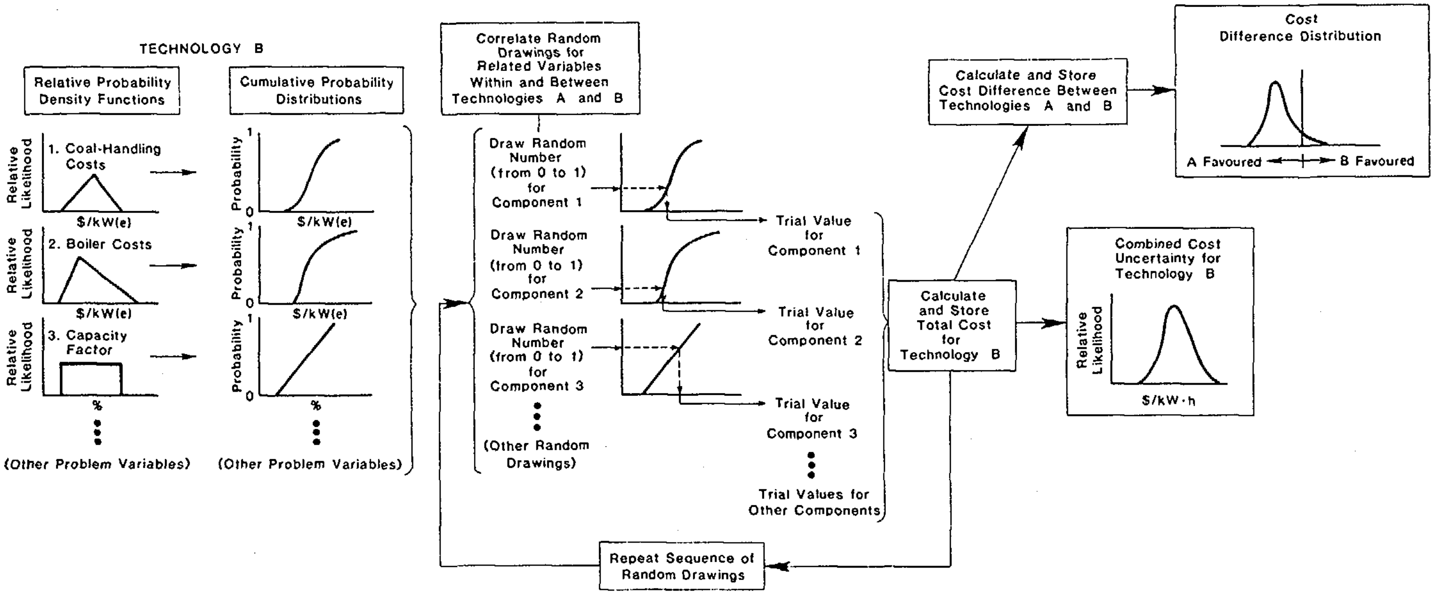


FIG. 6.8. Uncertainty model structure: the STATS Program.

facilities are partially correlated with boiler installation costs because they both require labour inputs. If the labour input is isolated from both components, it can be represented as a common component, i.e. totally correlated, while the remaining costs are treated independently (assuming that labour inputs are the only source of correlation). Detailed design information is required to determine the relative contributions made by the basic components to the cost of each subsystem of a technology.

6.4.3.4. Comparative cost measures

Total energy costs are one method of comparing alternative electricity generating technologies. Included are annualized capital costs, levelized fuel costs, and levelized operation and maintenance costs. Utility system integration costs (or credits) can also be included to account for system operations. A new unit will affect system reliability and other capacity requirements. At the same time, capacity factors for new units will be determined primarily by the nature of the existing utility system. Fuel types, unit sizes and load trends all affect the level of use for new generating units. Comparisons between alternative technologies can be influenced by these indirect effects.

The main difficulty in treating system integration effects is in deriving a consistent representation that can be modelled within the probabilistic framework. Correlations between system integration factors are likely to be very difficult to specify. Production cost models are usually required to determine these complex interactions. Computational considerations are unlikely to allow such detailed calculations to be embedded in the repetitive cycle of Monte Carlo trials. The possibility exists, however, of including simplified approximations of system integration factors if they can be performed rapidly enough to allow a large number of trials to be executed.

6.4.4. Applications

Comparisons between two advanced coal-conversion technologies are developed in this section to demonstrate a hypothetical application and potential implications of uncertainty analysis. The examples are not intended to be accurate studies of the two technologies but are merely illustrative of the analysis. For simplicity, component cost estimates are based on a single data source, and uncertainty distributions are represented by uniform distributions. Correlations are hypothesized for several of the case studies, but they are not developed by means of any sophisticated analysis. On the other hand, input assumptions are realistic enough to show how the information obtained from the uncertainty analysis could affect risk-dependent decision-making.

6.4.4.1. Comparative cost criterion

The equations below define the assumptions used to combine sampled component costs and performance characteristics into total costs. (These equations only provide one example of cost criteria that may be used for comparative purposes. Many other definitions of criteria or problem components are possible.) Included are the major categories of fixed and variable O&M costs, fuel costs and capital costs. Operational considerations such as heat rates and capacity factors are also included. Uncertainty assumptions for all these parameters follow the equations.

$$\text{Capital cost } (\$/\text{kW}\cdot\text{h}) = (\text{CRF}\cdot\sum C_i)/(8760\cdot\text{CF})) \tag{6.65}$$

where:

CRF is the capital recovery factor (%/a) (see Eqs (6.6) and (6.7))
C_i is the capital cost of subsystem i (\$/kW(e))
CF is the capacity factor (%)

$$\text{Variable cost } (\$/\text{kW}\cdot\text{h}) = (\text{VOM}\cdot L_1/10^3) + (\text{fuel}\cdot\text{HR}\cdot L_2/10^9) \tag{6.66}$$

where:

VOM is the variable O&M cost (mills/kW·h)
L_1 is the O&M levelization factor to account for future increases in cost as defined in Section 6.2.2
Fuel is the fuel cost (\$/10^9 J)
HR is the heat rate (J/kW·h)
L_2 is the fuel levelization factor (see Section 6.2.2)

$$\text{Fixed operating cost } (\$/\text{kW}\cdot\text{h}) = (100\cdot\text{FOM})/(8760\cdot\text{CF}) \tag{6.67}$$

where:

FOM is the fixed O&M cost (\$/kW·a)

Total cost (\$/kW·h) = capital cost (\$/kW·h) + variable cost (\$/kW·h) + fixed operating cost (\$/kW·h)

Equation (6.67) assumes that no real escalation occurs over time for fixed operating costs. If real escalation is to be included, then a levelization factor should be introduced as in Eq. (6.66).

TABLE 6.VIII. ILLUSTRATIVE CAPITAL COST ESTIMATES AND UNCERTAINTY RANGES
(Cost and uncertainty estimates are based primarily on Ref. [18])

Subsystem	Component	Capital costs[a] and uncertainty ranges[b] PFBC	CGCC
Materials handling	Coal handling	36.5(+10%)	26.4(+10%)
	Sorbent handling	19.0(+10%)	–
Boiler/combustor	Fluidized-bed combustor	132.3(+15%)	–
	Gasifier and oxidant	–	194.3(+15%)
Gas cleanup	Gas and stack cleanup	103.2(+5%)	115.1(+15%)
Waste handling	Waste handling	26.0(+5%)	22.7(+5%)
Power generation	Combined cycle	399.0(+5%)	568.0(+5%)
Total		716.0(+7.2%)	926.5(+8.5%)

[a] Capital costs are given in \$/kW(e) and represent minimum values for the uncertainty ranges. These minimum values were used for the deterministic cost calculations and are for illustration only.

[b] Additive uncertainty estimates are in parentheses and are expressed as percentages of the nominal values.

6.4.4.2. Component definitions and cost estimates

The categories selected for capital cost components were chosen to fit the definitions used in a cost-estimating feasibility study conducted by Burns and Roe [18]. This study was the primary source of capital cost estimates and uncertainty factors. Operational characteristics of the coal technologies are based on estimates from EPRI [4].

The two technologies chosen for comparison are pressurized fluidized-bed combustion (PFBC) and coal gasification with combined cycle (CGCC). The PFBC design includes two 500 MW(e) units whereas the gasifier design includes a 1000 MW(e) unit; for these comparisons, capital costs for the gasifier were adjusted to correspond to those for two 500 MW(e) units. Plant subsystems are broadly organized under functional headings of materials handling, boiler/combustor, gas cleanup, waste handling and power generation. Table 6.VIII shows illustrative capital cost estimates in \$/kW(e) for components in these subsystems.

TABLE 6.IX. PERFORMANCE AND ECONOMIC ASSUMPTIONS

Component	Estimated values and uncertainties[a]	
	PFBC	CGCC
Performance characteristics:		
Heat rate (10^3 J/kW·h)	9199(+5%)	8604(+5%)
Capacity factor (%)	59(−15%)	64(−15%)
Operational costs:		
Fixed O&M ($/kW·a)	12.0	18.0
Variable O&M (mills/kW·h)	5.5	2.7
Fuel ($/$10^9$ J)	1.42	1.42
Economic variables:		
Annual charge rate (%/a)	17.0	17.0
Fuel levelization factor	1.8	1.8
O&M levelization factor	1.6	1.6

[a] Uncertainties are in parentheses and are given in terms of percentage variation, using the base value as an optimistic estimate. The optimistic values were used for deterministic calculations. Where no uncertainty is specified, the values were kept fixed throughout the analysis.

These costs represent nominal values for the calculations; uncertainty costs are additive. Uncertainty factors are expressed in Table 6.VIII as a percentage of the minimum costs and are modelled in the examples using uniform distributions. Thus, the installed costs for coal-handling equipment in PFBC would be randomly set between 36.5 and 40.2 $/kW(e) in the simulations, while the same component of CGCC would be evenly distributed between 26.4 and 29.0 $/kW(e).

The major sources of uncertainties are assumed to arise from unforeseen factors in engineering estimates, which are particularly characteristic of unproven technologies. Allowances for site-specific design modifications have already been embedded in the basic cost estimates at a fixed percentage of 15% for each component. The estimates for uncertainties shown in Table 6.VIII are optimistic if they are expected to account for all possible sources of variation. However, the problem has been more narrowly defined in order to examine sources of uncertainty for which quantitative estimates were available.

Additional inputs are needed to estimate total energy costs. Table 6.IX describes the performance and economic inputs, primarily developed from two literature sources [17, 18]. Components under the headings of operational costs and economic variables were held fixed for these examples in order to focus on the effects of capital cost and performance variations. Normally some uncertainty would be associated with the other factors.

As in Table 6.VIII, the uncertainty ranges given in Table 6.IX were treated as penalties for the base costs and performance estimates. The underlying assumption is that the base estimates are optimistic and that uncertainties will tend to make costs increase and performance decline from their nominal values. This assumption is particularly important for comparisons with deterministic costs. Results for deterministic calculation ('best estimates') are included for comparison with the probabilistic outcomes. They are based on the nominal (optimistic) values for each of the problem variables and do not incorporate any penalties for cost or performance uncertainties.

Results will show that deterministic calculations could lead to significantly different conclusions from the probabilistic calculations. All the probabilistic results favour PFBC over CGCC while the deterministic result shows the reverse. This is due, in part, to the use of the optimistic base values for deterministic calculations. For these particular examples, the uncertainty estimates tend to penalize CGCC more than PFBC. However, these results are not intended to imply that such distinct contrasts are necessary in order to support the use of probabilistic analysis. The main strength of probabilistic techniques is that they display information lacking in deterministic approaches regardless of whether the deterministic outcome agrees with averaged probabilistic results.

6.4.4.3. Correlation assumptions

Initially, the uncertainty factors were all treated independently. To contrast these results, correlations between sets of variables were introduced. One strategy was to correlate capital costs completely for the four common components of coal handling, gas cleanup, waste handling and combined-cycle equipment. In other words, when sampled costs for gas cleanup in PFBC were high, so were gas cleanup costs for CGCC. Other categories of capital costs are unique to each technology, so the costs for sorbent handling, the fluidized-bed combustor, gasifier and oxidant have been treated independently in all the trials.

Correlations between capacity factors of the two technologies were introduced to represent crudely possible system integration effects. For these two technologies, utility system characteristics that would dictate high capacity factors in PFBC would probably do the same for CGCC.

6.4.4.4. Results

Distributions of cost differences are the focal point of the following discussions. For technology comparisons, the distributions of cost differences convey more information about potential benefits and risks of R&D decisions than do distributions of single technology costs. For the graphic displays of results (Figs 6.9,

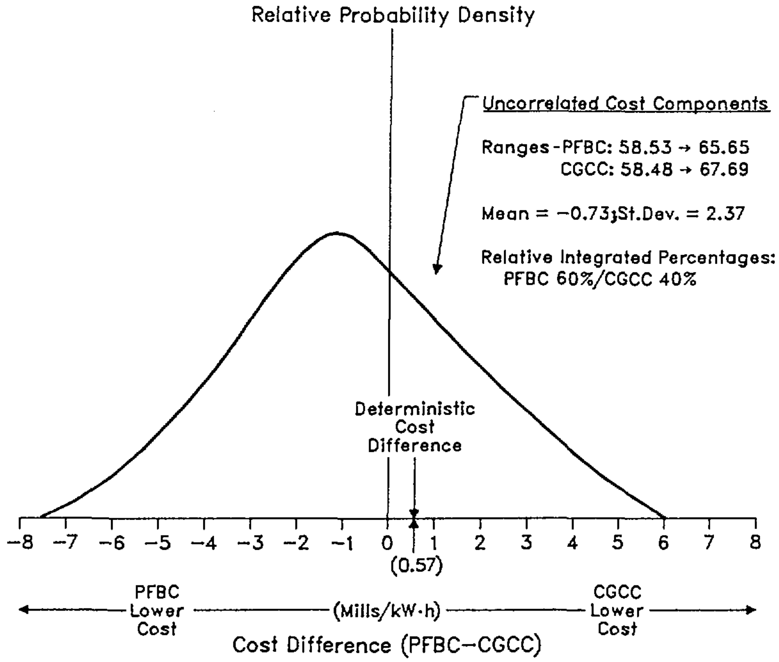


FIG. 6.9. Case 1: technology comparison with no correlated uncertainties (see Table 6.X for problem-variable specification).

10 and 11), the area under each probability curve that is left of centre represents outcomes where PFBC would be a cheaper energy source than CGCC. The area under the right side of each curve corresponds to the probability of CGCC providing lower-cost generation. As an indication of the variations introduced by each set of assumptions, ranges for total costs of each technology are displayed. Statistical means and standard deviations are displayed in addition to the relative integrated probabilities that either technology will provide lower energy costs.

6.4.4.5. Case 1: Independent cost and uncertainty estimates

Figure 6.9 shows the results of using independent cost and uncertainty estimates (specified in Tables 6.VIII and IX). Table 6.X summarizes the problem variables and assumptions. The distribution in Fig.6.9 shows relative probabilities for cost differences between PFBC and CGCC. In each random trial, capital costs for waste handling can be high for PFBC but low for CGCC or vice versa. Independence between problem variables tends to spread out the range of cost differences.

TABLE 6.X. PROBLEM VARIABLES AND ASSUMPTIONS FOR CASE 1: TECHNOLOGY COMPARISON WITH NO CORRELATED UNCERTAINTIES

Problem variables	Value ranges[a] PFBC	CGCC
Capital costs ($/kW(e)):		
Coal handling	36.5–40.2	26.4–29.0
Sorbent handling	19.0–20.9	–
Fluidized-bed combustor	132.3–152.1	–
Gasifier and oxidant	–	194.3–223.4
Gas and stack cleanup	103.2–108.8	115.1–132.4
Waste handling	26.0–27.3	22.7–23.8
Power generation	399.0–419.0	568.0–596.4
Performance characteristics:		
Heat rate (10^3 J/kW·h)	9199–9659	8604–9036
Capacity factor (%)	59–50	64–54

[a] All uncertainty ranges have been represented by uniform probability-density functions that give equal likelihood to the selection of any given value within each variable range.

Note: Operation costs (fixed and variable O&M), fuel costs and economic variables (annual charge rate and levelization factors) were all held at fixed values for the examples in this study.

This case is an initial comparison of costs, with no correlations assumed. All the uncertainty ranges are treated independently.

For the hypothetical assumptions used in Case 1, results indicate that the PFBC technology has a 60% probability of being the lower-cost alternative. The mean value of the distribution corresponds to a 0.73 mills/kW·h cost advantage for PFBC. If costs are calculated deterministically (no uncertainty), the comparison reverses. Costs for PFBC would be 0.57 mills/kW·h higher than for CGCC[10]. A dominant factor in this disparity is the capacity factor uncertainty that penalizes the CGCC technology more severely than the PFBC technology, even though the percentage variations are equal. With higher capital costs, the gasifier must maintain a high utilization (capacity factor) in order to compete with fluidized-bed combustion on the basis of costs per kW·h.

[10] This deterministic result is based on the optimistic values estimated for costs and performance. If the least favourable values are used, PFBC would have a 1.29 mills/kW·h advantage. If mean values are used for each variable, PFBC would have a 0.20 mills/kW·h advantage.

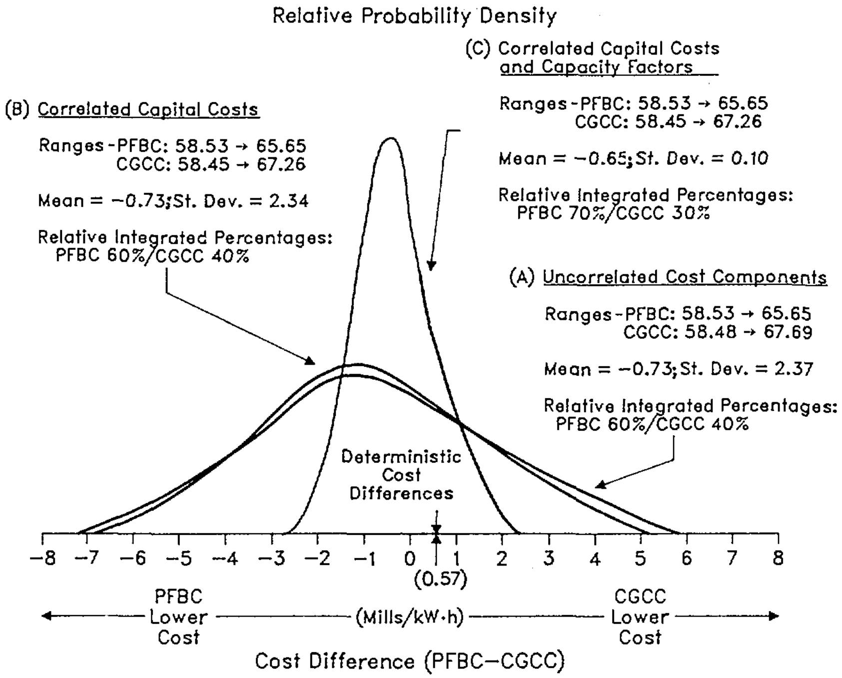


FIG. 6.10. Case 2: technology comparison with variations in correlation assumptions.
(A) No correlation is assumed.
(B) Capital-cost components for coal handling, gas cleanup, waste handling and power generation equipment are totally correlated. Other capital costs and performance characteristics are treated independently.
(C) In addition to capital-cost correlations described in (B), the variations in capacity factors are directly correlated.

6.4.4.6. Case 2: Correlations in capital costs and capacity factors

Correlations tend to tighten the distributions of cost differences. Figure 6.10 compares the uncorrelated case (distribution A) with two alternatives. In one case, the common capital cost components are totally correlated (distribution B). These components include the costs of coal handling, gas cleanup, waste handling and combined-cycle equipment. The other capital components are not correlated because of inherent differences between technologies. In another test, capacity factor correlations are included with capital cost correlations (distribution C).

Potential sources of capital cost dependences can be hypothesized in terms of common material and labour requirements. Correlations in capacity factors might be hypothesized in terms of dispatch priorities within utility systems. Plant use is partly determined by the relative economies of the PFBC or CGCC units in relation to other utility units of a system. Operational costs for PFBC and CGCC are similar enough that utility conditions giving rise to high utilization of one would probably cause high use of the other.

A comparison between curves (A) and (B) in Fig. 6.10 shows only minor sensitivity to the capital cost correlations. Since capacity factors were assumed independent for this case, a large degree of randomness is maintained in capital contributions to total energy costs. The uncertainty assigned to capacity factors would cause the capital portion of total energy costs ($/kW·h) for each technology to remain distributed even if there were no uncertainties in capital costs ($/kW(e)).

The narrowest distribution, curve (C), corresponds to the case in which capacity factors are completely correlated. This effect is not due to smaller variations in the individual technologies, but rather to the correspondence between variations. With capital components and capacity factors correlated, the conditions that give rise to high costs and low output for PFBC result in the same characteristics for CGCC. Similarly, low energy costs for PFBC are associated with low costs for CGCC. The only sources of differences are in the uncorrelated capital components (unique to each technology) and in the variable heat rates. The probability of PFBC being the lower-cost alternative increases from 60% to 70% with assumed increase in correlations.

6.4.4.7. Case 3: Sensitivity to uncertainty in capacity factors

Because capacity factors are important in the comparisons, two additional variations were made. In one case the uncertainty for capacity factors was reduced from the base value of 15% (distribution A) to 10% (distribution B). Another trial entirely removed the uncertainty in capacity factors (distribution C). Figure 6.11 shows the narrowing in distributions that occurs with decreasing uncertainty in capacity factors.

The standard deviation is reduced from 2.34 mills/kW·h with 15% uncertainty to 0.10 mills/kW·h with fixed capacity factors. The corresponding mean values shift from –0.73 to 0.13 mills/kW·h. Cumulative probabilities favour PFBC 60% of the time when capacity factor contingencies are 15%. With fixed capacity factors, the comparative probabilities are nearly equivalent (55% versus 45%).

6.4.4.8. Summary

Results for Case 1 illustrate the potential for contrasts between probabilistic and deterministic comparisons. The deterministic calculation shows CGCC to have a small cost advantage (0.57 mills/kW·h). However, this result hinges on the simultaneous occurrence of the single best estimates for all the cost and performance components. This is a very low probability event in view of the uncertainties for future developments in design, construction, resources and operations. When variations are treated for major problem components, significant changes occur in

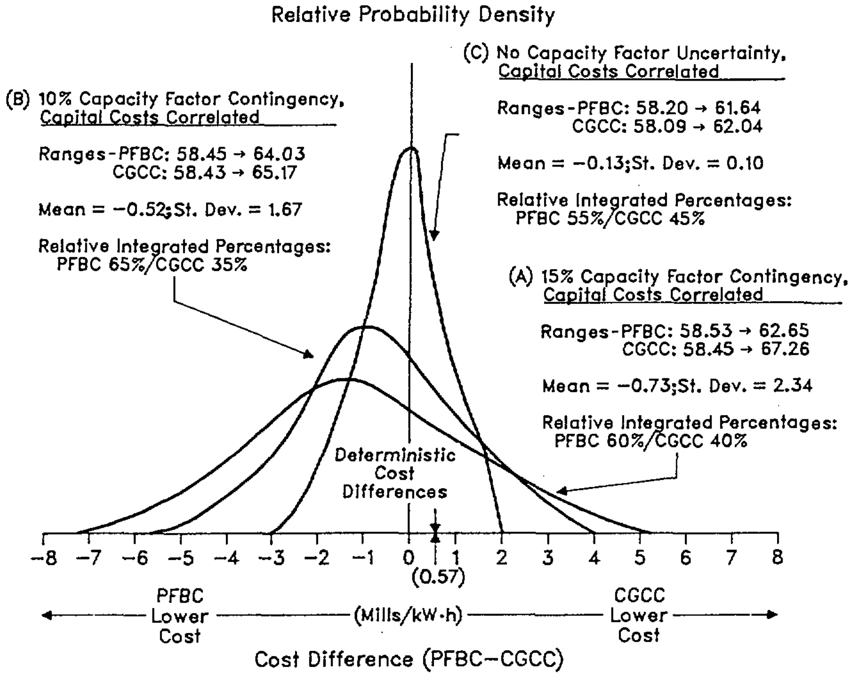


FIG. 6.11. Case 3: technology comparison with variations in capacity factor uncertainties.
(A) 15% uncertainty in capacity factors is included independently for each technology (this is the nominal value used for other cases). Common capital-cost components are correlated (i.e. coal handling, gas cleanup, waste handling and power generation equipment).
(B) 10% capacity factor uncertainty is assumed. Common capital costs are correlated.
(C) No uncertainty is assumed for capacity factors. A 59% capacity factor is used for PFBC and 64% is used for CGCC. Common capital costs are correlated.

the comparisons. It is extremely difficult to predict the effects of uncertainty without using a simulation tool that can account for multiple variations, some of which are augmented with combined effects and others with offsetting influences.

The potential importance of correlation assumptions is pointed out by the variations in results for Case 2. Effects of correlated components can affect the apparent attractiveness of competing technologies as well as the risks for technology choices. Capital cost correlations made very little difference in the comparisons of these two technologies. However, capacity factor correlations significantly affected both the relative probabilities and the magnitude of potential cost differences.

Characteristics for PFBC and CGCC are similar enough for the probabilistic comparisons not to be widely skewed in the examples. Other technology comparisons have the potential to show one option favoured according to the expected value of cost differences, but also associated with greater risks for cost overruns. It is important to quantify this type of information with as much confidence as possible for the decision processes which attempt to integrate risks, values and objectives in technology choices.

Results for Case 3 emphasize the potential importance of uncertainty estimates. The ranges of uncertainty in capacity factors directly affected the ranges and relative probabilities of cost differences. If uncertainty estimates are not well known, it is useful to perform some sensitivity analysis. For some parameters, the uncertainty assumptions are not critical; for others, the assumed ranges of variation have a major influence on probabilistic comparisons.

6.4.5. Conclusions

The examples are only intended to illustrate probabilistic uncertainty analysis. Results should not be interpreted as an indication that PFBC is superior to CGCC. Cost and performance estimates are too preliminary and problem components are insufficiently detailed to support major conclusions. More definitive comparisons would require refinements in uncertainty estimates, more detailed descriptions of problem components, and consideration for site- and application-specific factors. The examples do provide insights into the use of uncertainty analysis that allow some general conclusions and observations to be made.

Probabilistic comparisons incorporate the effects of uncertainties inherent in technology evaluations. Decisions sensitive to issues of risk and uncertainty are aided by the information developed in the probabilistic approach. Deterministic approaches can provide ranges of possible outcomes, but important information is missing regarding the likelihood of various alternative outcomes. The strength of probabilistic approaches such as the one described here is that complete ranges of possible values for key factors can be treated simultaneously. The combined effects of uncertain components and correlations are explicitly calculated in order to provide a consistent basis for comparisons. Four major features of the uncertainty analysis are outlined below:

- The analysis produces quantitative comparisons that can be graphically displayed;
- Problem formulations can be made as simple or as sophisticated as dictated by the availability of data and expert opinion;
- Correlated sources of uncertainty can be treated explicitly;
- Results are appropriate for interfacing with expansion planning studies, R&D efforts and related decision analysis.

The primary limitations for uncertainty analysis in expansion planning studies arise from computational restrictions. Since many repetitions are required for representative sampling of probability distributions, the manageable complexity of simulations is limited. Nevertheless, it may be possible to use simplified representations of utility system models in order to directly treat the system integration effects of capacity expansions within the framework of uncertainty analysis.

Probabilistic simulations can supplement, but not replace, some of the detailed deterministic calculations for capacity expansion analysis. Deterministic simulations are able to treat in great detail many system integration factors, but not uncertainties in parameter estimates. Deterministic optimization programs are especially prone to selections based on false criteria, in that minute cost advantages for a technology will always result in the selection of that technology (even when the cost advantage is much smaller than the degree of uncertainty).

When it is recognized that difficulties exist, there are several possible means for improvement. To begin with, the probabilistic analysis should be conducted with as much detail as allowed by computational constraints (i.e. maximum program size and execution costs). For example, the screening curve method outlined in Section 6.6 below could be efficiently combined with probabilistic simulations in order to examine the approximate effects of uncertainties on optimal technology mixes. The inherent limitations of screening curves still persist. The tradeoffs between more detailed probabilistic simulations and increased computation requirements must be balanced.

Once the appropriate level of probabilistic simulation detail is determined, results must be examined for implications regarding deterministic optimization studies. Differences should be reconciled, especially in cases where technology choices are close. Changes in deterministic inputs (from the original best estimates) might be appropriate after the combined effects of multiple probabilistic relationships are taken into consideration in order to account for system integration effects. In either case, something can be learned from differences in conclusions derived from the two simulation techniques. Results from probabilistic and deterministic calculations are best used in conjunction to provide insights into capacity expansion problems that cannot be achieved separately by either technique.

Formal applications of the uncertainty analysis require further attention in areas of component definitions, cost and performance uncertainty estimates, and correlation representations. It appears that cost and performance uncertainties can be sufficiently characterized by consultation with experts and by literature surveys. Increased detail in defining problem components usually assists in identifying correlations. Partial correlations between major elements of a technology can in some cases be simplified by disaggregation into identical or near-identical, totally correlated subcomponents and independent unique subcomponents.

While it may be difficult to construct probability functions precisely for cost and performance uncertainties, an analysis based on even rough approximations provides insights into the potential implications of uncertainty. Decisions on technology choices must deal with uncertainties. The assumptions regarding uncertainties are often implicit in the decisions or are embedded throughout the cost and performance estimates without consideration of their combined effects. The decisions can be improved if an effort is made to recognize and quantify the uncertainties explicitly. The probabilistic model can be summarized as a tool that is relatively easy to understand and use. It is not a means for removing uncertainty from technology choices; it is a method that yields insights into the combined effects of many component uncertainties.

6.5. PRODUCTION COST ANALYSIS

In this section an explanation is given for the probabilistic simulation method of determining expected generation from a group of generating units. Following an illustrative example, some typical complications are discussed, such as blocking of units, spinning reserve, and purchases. The problems of accuracy tradeoffs are also discussed. Finally, some recent innovations are briefly reviewed.

The discussion and subsequent example calculation focus on a simplified generating system composed of thermal units only. Emphasis is placed on the modelling of random forced outages of generating units, which is the only time, apart from scheduled maintenance outage, when thermal units are assumed to be unable to supply generation. For hydroelectric generating units, there are two distinct additional types of failure:

– Energy deficit, e.g. lack of water in the reservoir,
– Power deficit due to a variable head.

The first type of failure primarily affects production costs, while the second is of primary concern for system reliability. Proper representation of hydroelectric operation requires complex simulations of hydro inflows and storage, as discussed in Chapter 8.

6.5.1. Role of production cost analysis in generation planning

As discussed in the preceding sections, the mix and characteristics of the generating units in a system affect the generation that is expected from any particular unit. A key part of any generation planning effort is estimating the fuel and variable O&M expenses expected for a particular configuration of the system in a particular time period. These calculations must be performed repeatedly for optimizations over long time horizons; they must be reasonably accurate representations of the expected system performance, and must not be prohibitively complicated so that computer time becomes a severe limitation for performing thorough sensitivity analyses.

An important step toward more sophisticated generation planning techniques was the development of probabilistic simulation for calculating expected production costs (see e.g. Refs [19–21]). Probabilistic simulation provides a mathematically rigorous method for simulating random forced outages of generating units and, in turn, for estimating capacity factors for all the generating units in the system. Just as any modelling technique is an imperfect representation of the real world, probabilistic simulation does not allow exact simulation of all operating considerations facing a generating system. However, depending on the accuracy needed for a particular application, more detailed representations and improved assumptions can be used to obtain more accurate results at the cost of a more complicated and time-consuming analysis. For example, if the generation planner was interested in preparing estimates of fuel needs for the next year or two, a more detailed production cost analysis would be desirable than if alternative expansion plans are being examined over a 30 year planning horizon.

6.5.2. Loading order for generating units

To calculate the expected generation from a group of generating units, a loading order (sometimes called the merit order) must be established. The loading order states the order in which the individual units are expected to be called upon to meet the demand facing the generating system. (For simplicity in the following example calculations, generating units will be considered to consist of a single block of capacity. Multiple block representations are discussed in Section 6.5.6.)

To illustrate the principles of probabilistic simulation, a fictitious example is used throughout this section. The characteristics of the generating units for this example are listed in Table 6.XI. The generating units are listed in the order in which they would be loaded if the economic loading order were followed, i.e. the unit with the lowest variable cost of production is loaded first, . . . , and the unit with the highest variable cost is the last unit called upon to generate. As discussed in Section 6.3 above, the loading order will be altered from the apparent economic loading order by practical considerations such as spinning reserve.

6.5.3. Load representation

If chronological hourly loads of a utility are plotted against the hour of occurrence during an extended period, say a day or a week, the resulting curve gives a chronological representation of the hourly power demand required from the electric system. A hypothetical daily load curve with a sharp afternoon peak load is shown in Fig. 6.12(a). The area under the curve is the energy requirement to be delivered by the power system. If these same hourly loads are rearranged against the same abscissa in decreasing order of magnitude, the resulting curve is the load duration curve, previously defined in Chapter 4. Figure 6.12(b) shows the load duration curve corresponding to the chronological curve in Fig.6.12(a). The area under the resulting curve is identical to the chronological representation and still represents the kW·h energy requirement of the system. The meaning of the abscissa is now the number of hours the load equals or exceeds the corresponding

TABLE 6.XI. CHARACTERISTICS OF GENERATING UNITS FOR A FICTITIOUS GENERATING SYSTEM

Unit No.	Unit name	Rated capacity (MW(e))	Forced outage (%)	Type of fuel	Variable cost ($/MW·h)
1	NUC1	200	20	Nuclear	6.5
2	NUC2	200	20	Nuclear	6.5
3	COAL1	200	10	Coal	27.0
4	COAL2	200	10	Coal	27.0
5	OIL1	100	10	Oil	58.1
6	OIL2	100	10	Oil	58.1
7	OIL3	100	10	Oil	58.1
8	OIL4	100	10	Oil	58.1
9	CT1	100	5	Distillate oil	113.2
System capacity		1300			

Note: These names and numbers were selected in order to present a simple example of probabilistic simulation. No significance should be attached to the names or numbers listed. More realistic values for generating units are given in Appendices G and H.

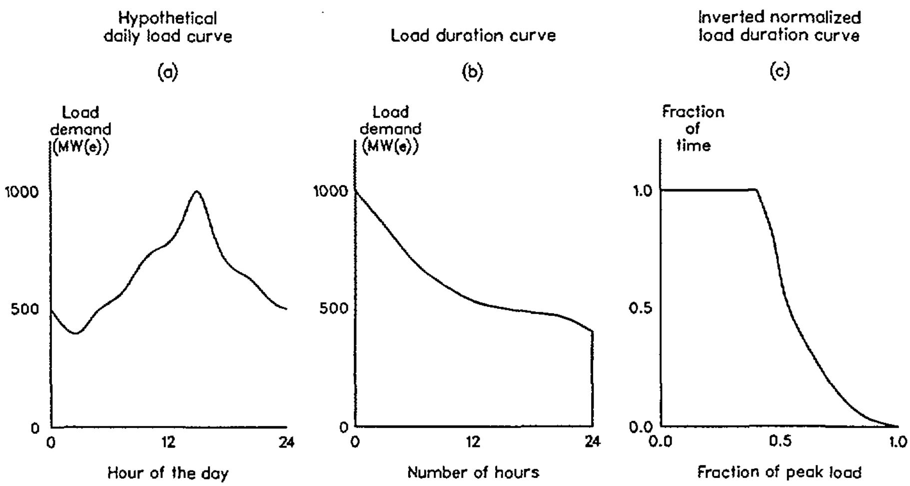


FIG. 6.12. Representations of load data.

TABLE 6.XII. LOAD DURATION CURVE

Load MW(e)	Fraction of time load exceeds given load
0	1.00
100	1.00
200	1.00
300	1.00
400 (minimum load)	1.00
500	0.80
600	0.40
700	0.20
800	0.10
900	0.05
1000 (peak load)	0.00

load. The load duration curve can be further transformed by normalizing each axis to a reference value; the resulting curve, converted by interchanging the x and y axes for computational convenience, is called the inverted normalized load duration curve (Fig.6.12(c)). For any chosen value of the fraction of peak load, the associated ordinate is the probability that the chosen load will be equalled or exceeded at any randomly chosen time during the period.

Let us use the daily load duration curve in Fig. 6.12 as if it were the annual load duration curve for the example problem. The data for the assumed load duration curve are shown in Table 6.XII. Load intervals of 100 MW(e) have been used for convenience of calculation. The incremental load probability for any load interval can be determined by subtracting the corresponding fraction of time for the upper bound of the load interval from the fraction of time for the lower bound of the load interval. For example, the probability that the load falls between 400 and 500 MW(e) is 1.0–0.8, or 0.2.

The incremental load curve can be used to calculate the total demand in kW·h (energy requirement) by associating the probability with the midpoint of the load interval; for example, the probability of the load being 450 MW(e) is 0.20. The calculation of total demand is shown in Table 6.XIII for a year (8760 hours) and the load duration curve is given in Table 6.XII. The load factor, the energy demand divided by the quantity peak load times hours in the period, is 0.605 for the example problem.

TABLE 6.XIII. TOTAL DEMAND BY LOAD INTERVAL

(a) Load (MW)	(b) Load probability	(c) 10^6 kW·h/a	(d) Contribution to average demand ($\overline{MW}$(e)) ((a) X (b))
50	0.00	0	0
150	0.00	0	0
250	0.00	0	0
350	0.00	0	0
450	0.20	788.4	90
550	0.40	1927.2	220
650	0.20	1138.8	130
750	0.10	657.0	75
850	0.05	372.3	42.5
950	0.05	416.1	47.5
		5299.8	605.0

Load factor: 5299.8 X 10^6 kW·h/(10^6 kW(e) X 8760 h) = 0.605, or
Load factor: 605 $\overline{MW}$(e)/1000 MW(e) = 0.605.

6.5.4. Capacity outage distribution

A stochastic method of treating the reliability of a generating unit is to assign a probability to each of its possible states of available capacity. A generating unit (labelled unit 1) of total capacity c_1 can be in one of s states such that the available capacity is $a_{1,i}$ if it is in state i. The probability of being in state i is $p_{1,i}$ and the sum of the $p_{1,i}$ is 1.0. Alternatively, when the unit is in state i, the unavailable capacity for the capacity in outage, $b_{1,i}$ is equal to c_1–$a_{1,i}$.

The simplest stochastic method of treating the reliability of a generating unit is to assign it only two possible states of availability, i.e. s = 2. Either it is available or it is not. Under this assumption, if the unit is available it is capable of full power output ($a_{1,1} = c_1$). If the unit is unavailable it is capable of no power output ($a_{1,2} = 0$). Let $p_{1,1} = p_1$ be the probability that unit 1 is available and $p_{1,2} = q_1$ be the probability that the unit is not available. In this case $p_1 + q_1 = 1$. This is the approach used in WASP-III. The outage probability is the equivalent forced outage rate defined in Section 6.3 above. This definition of forced outage represents the likelihood that a generating unit will not be able to generate when called upon during periods when the unit is not scheduled for maintenance.

Let us consider a system of G generating units. The index N refers to the N-th unit out of the total G units. A probability distribution of available capacity from the first unit through the N-th unit, $D_N(x)$, can be constructed for part or all of the generating system having individual units with capacity $c_1, c_2, \ldots, c_G$. Each of the units can have s states. The probability is $p_{N,i}$ that the unit is in state i and the available capacity is $a_{N,i}$; for simplicity of notation it is assumed that s is the same for all G units but that is not generally the case. The units are assumed to be brought on line in a preassigned loading order. If all combinations of available capacities among the N units and their probabilities are developed, the available capacity probability function $D_N(x)$ can be defined: $D_N(x)$ is the probability that the available capacity of the system composed of N units is equal to x. The function $D_N(x)$ can be developed recursively by means of Eq. (6.68), where the sum of the $p_{N,i}$ over $i = 1, \ldots, s$ is 1.0:

$$D_1(a_{1,i}) = p_{1,i} \qquad (i = 1, \ldots, s)$$

$$D_N(x) = \sum_{i}^{s} p_{N,i}\, D_{N-1}(x - a_{N,i}) \tag{6.68}$$

The probability of having an available capacity equal to x is the sum of the compounded probabilities of all events producing an available capacity equal to x. The function $D_N(x)$ is built up by adding to the system one unit at a time. In the two-state model (used in WASP) the recursive relationship is shown by Eq. (6.69):

$$D_1(c_1) = p_{1,1} = p_1$$

$$D_1(0) = p_{1,2} = q_1$$

$$D_N(x) = p_N\, D_{N-1}(x - c_N) + q_N\, D_{N-1}(x) \tag{6.69}$$

$$p_N + q_N = 1$$

where

p_N is the probability that unit N is available, and
q_N is the probability that unit N is not available in the non-maintenance period being analysed (equivalent forced outage rate).

The values of the x achievable are

$$\sum_{i=1}^{N} c_i\, \delta_i$$

TABLE 6.XIV. CALCULATION OF THE AVAILABLE CAPACITY DISTRIBUTION

p_N =	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.95
q_N =	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.05
c_N =	200	200	200	200	100	100	100	100	100
x (MWe)	$D_1(x)$	$D_2(x)$	$D_3(x)$	$D_4(x)$	$D_5(x)$	$D_6(x)$	$D_7(x)$	$D_8(x)$	$D_9(x)$
0	0.2	0.04	0.004	0.0004	0.00004	0.00000	0.00000	0.00000	0.00000
100	0.0	0.0	0.0	0.0	0.00036	0.00007	0.00001	0.00000	0.00000
200	0.8	0.32	0.068	0.0104	0.00104	0.00043	0.00011	0.00002	0.00000
300	0.0	0.0	0.0	0.0	0.00936	0.00187	0.00057	0.00015	0.00003
400	0.0	0.64	0.352	0.0964	0.00964	0.00939	0.00262	0.00078	0.00018
500	0.0	0.0	0.0	0.0	0.08676	0.01735	0.01019	0.00338	0.00091
600	0.0	0.0	0.576	0.3744	0.03744	0.08183	0.02380	0.01155	0.00379
700	0.0	0.0	0.0	0.0	0.33696	0.06739	0.08039	0.02946	0.01245
800	0.0	0.0	0.0	0.5184	0.05184	0.30845	0.09150	0.08149	0.03206
900	0.0	0.0	0.0	0.0	0.46656	0.09331	0.28693	0.11104	0.08297
1000	0.0	0.0	0.0	0.0	0.0	0.41991	0.12597	0.27084	0.11903
1100	0.0	0.0	0.0	0.0	0.0	0.0	0.37791	0.15117	0.26485
1200	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.34012	0.16062
1300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.32311
TOTAL	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

$D_N(x)$ is the probability that the available capacity of the system composed of N units is equal to x. Entries of 0.0 mean exactly zero (an unattainable state) while 0.00000, such as $D_9(0)$, mean a nonzero value less than 0.00001.

where δ_i is 0 or 1. Thus, 2^N possible values result, although not all states may be different, e.g. $c_3 + c_4$ may equal $c_1 + c_2$.

The calculation of the available capacity distribution for the example problem is shown in Table 6.XIV (scheduled maintenance is being ignored for the present). For the entries under $D_1(x)$ to $D_4(x)$, only even multiples of 200 MW(e) are possible available capacity states because units 1 to 4 are all 200 MW(e). Values of 0.0 in Table 6.XIV, such as $D_3(300)$, mean that the state is not attainable. Values of 0.00000, such as $D_9(0)$, mean that the probability is non-zero but less than 10^{-5} ($D_9(0)$ is 2.0×10^{-9}). As an example of the calculation, $D_3(200)$ is obtained by multiplying $D_2(0)$ by 0.9 (the probability that the 200 MW(e) unit 3 is available) and adding to the product of $D_2(200)$ times 0.1 (the probability that unit 3 is not available). The result is that $D_3(200)$ equals 0.068. The calculation clearly becomes unwieldy as G becomes large and x becomes large.

The outage probability distribution, $O_N(x)$, is defined as the probability that the capacity in outage is equal to x. This function can be derived from the function $D_N(x)$, defined above, by using Eq. (6.70):

$$O_N(I - x) = D_N(x) \qquad \text{where} \qquad I = \sum_{j=1}^{N} c_j \tag{6.70}$$

The outage probability distribution can also be developed direct using the outage probabilities $q_{N,i}$ of capacities $b_{N,i}$ of the generating units and the recursive formula given by Eq. (6.71):

$$O_N(x) = \sum_{i=1}^{s} q_{N,i}\, O_{N-1}(x - b_{N,i}) \quad \text{where} \quad \sum_{i=1}^{s} q_{N,i} = 1 \tag{6.71}$$

In the two-state model for each generating unit, the relationship shown in Eq.(6.71) reduces to the recursive relationship shown in Eq. (6.72):

$$O_N(x) = p_N\, O_{N-1}(x) + q_N\, O_{N-1}(x - c_N) \qquad \text{where } p_N + q_N = 1 \tag{6.72}$$

6.5.5. Equivalent load

To determine the expected generation from any unit in the system, both the probability distribution for the load and the probability distribution for the forced outages of capacity must be considered. A convenient way to do this is to think of the generating units on outage as supplying their rated capacities to the system but at the same time imposing a load exactly equal to their rated capacities. The definition of equivalent load is the sum of load and unavailable capacity (unavailable is used here to mean strictly forced outages; if a unit is on scheduled maintenance, it is assumed to be excluded from the list of generating units that could help serve demand. More discussion of maintenance follows in Section 6.5.6):

$$x_e = x_\ell + x_q \tag{6.73}$$

where x_e is the equivalent load, x_ℓ is the load and x_q is capacity on forced outage.

With this definition of load, all machines on the system, whether on forced outage or not, contribute to the supply. Care must be taken in computing energy though, since only part of the area under the equivalent load duration curve (ELDC) is true load energy. The cumulative probability distribution of the ELDC, defined as $L_N(x)$, gives the total probability that the load plus the capacity on outage equals or exceeds a given value x when the generating system through the N-th unit out of G total units is being considered. $L_N(x)$ can be calculated using Eq. (6.74):

$$L_0(x) = \text{probability that load} \geqslant x$$

$$L_N(x) = \sum_{i=1}^{s} q_{N,i}\, L_{N-1}(x - b_{N,i}) \qquad \text{where} \sum_{i=1}^{s} q_{N,i} = 1 \tag{6.74}$$

The initial load duration curve is convolved with the outage probabilities of the N units, adding one unit at a time. The area under the equivalent load duration curve $L_N(x)$, corresponding to the position in the loading order for unit N+1, represents the energy that would be generated by unit N+1 if that unit did not itself suffer any forced outages. The actual expected generation can be determined by multiplying this area by p_{N+1}, which is 1.0–equivalent forced outage rate. Thus, the ELDC accounts not only for expected load observed by any unit in the system when all units are available for service, but also for all combinations of forced outages of units that are loaded before the unit for which energy generation is being determined. In the two-state model, the recursive formula for $L_N(x)$ is given as:

$$L_N(x) = q_N\, L_{N-1}(x - c_N) + p_N\, L_{N-1}(x) \tag{6.75}$$

where $p_N + q_N = 1$. Figure 6.13 shows (1) the original load curve ($L_0(x)$), (2) the ELDC observed by unit 2 ($L_1(x)$), and (3) the equivalent load duration curve

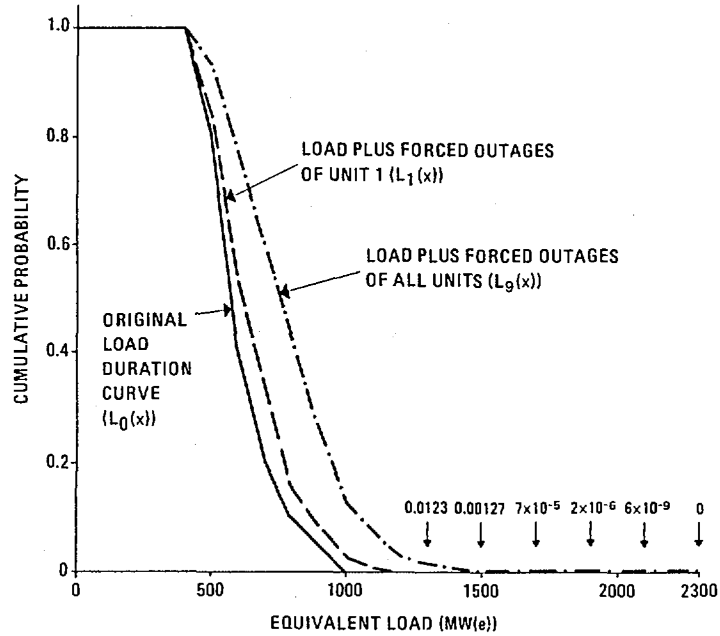


FIG. 6.13. Equivalent load duration curves for the example.

considering the forced outages of all units in the system $L_9(x)$. A unit of area in Fig. 6.13 is not energy because the y-axis is measured in normalized time (cumulative probability). Therefore, to obtain energy the area must be multiplied by the hours in the time period covered by the original load curve.

The results for the ELDCs for the example are given in Table 6.XV. $L_0(x)$ is the original load duration curve (Table 6.XII). $L_1(x)$ is the ELDC that accounts for the actual loads and the forced outages of unit 1 (a 200 MW(e) unit with a forced outage probability of 0.20). $L_9(x)$ is the ELDC that accounts for the actual loads and the forced outages of all nine units in the generating system. Blanks in the table represent impossible situations, e.g. $L_0(1100)$ and $L_3(2000)$. Underlining indicates the sum of generating unit capacities considered up to that point. The value of the ELDC for all units in the system at the point of system capacity ($L_9(1300)$) is the loss of load probability for the generating system (see Chapter 7).

As an example of the calculation of the equivalent load duration curve, $L_1(500)$ is derived from two situations: (1) an equivalent load of 500 MW(e) and unit 1 available (since unit 1 is available, it does not add to the equivalent load), and (2) an equivalent load of 300 MW(e) and unit 1 not available (unit 1's outage adds 200 MW(e) to the equivalent load). The probability of situation 1 is $L_0(500)$ times 0.8, or 0.64. The probability of situation 2 is $L_0(300)$ times 0.2, or 0.20.

TABLE 6.XV. CALCULATION OF EQUIVALENT LOAD DURATION CURVES

q_N =		0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.05
p_N =		0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.95
c_N =		200	200	200	200	100	100	100	100	100
x (MWe)	$L_0(x)$	$L_1(x)$	$L_2(x)$	$L_3(x)$	$L_4(x)$	$L_5(x)$	$L_6(x)$	$L_7(x)$	$L_8(x)$	$L_9(x)$
0	1.00	1.00	1.000	1.0000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
100	1.00	1.00	1.000	1.0000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
200	1.00	1.00	1.000	1.0000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
300	1.00	1.00	1.000	1.0000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
400	1.00	1.00	1.000	1.0000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
500	0.80	0.84	0.872	0.8848	0.89632	0.90669	0.91602	0.92442	0.93198	0.93538
600	0.40	0.52	0.616	0.6544	0.68896	0.70970	0.72940	0.74806	0.76570	0.77401
700	0.20	0.32	0.424	0.4688	0.51040	0.52826	0.54640	0.56470	0.58304	0.59217
800	0.10	0.16	0.232	0.2704	0.30880	0.32896	0.34889	0.36864	0.38825	0.39799
900	0.05	0.08	0.128	0.1576	0.18872	0.20073	0.21335	0.22708	0.24124	0.24859
1 000	0.00	0.02	0.049	0.0664	0.08680	0.09699	0.10736	0.11798	0.12889	0.13451
1 100		0.01	0.024	0.0344	0.04672	0.05073	0.05536	0.06056	0.06630	0.06943
1 200		0.00	0.004	0.0084	0.01420	0.01745	0.02078	0.02424	0.02787	0.02979
1 300			0.002	0.0042	0.00722	0.00792	0.00887	0.01006	0.01148	0.01230
1 400			0.00	0.0004	0.00120	0.00180	0.00241	0.00306	0.00376	0.00415
1 500				0.0002	0.00060	0.00066	0.00077	0.00093	0.00114	0.00127
1 600				0.00	0.00004	0.00010	0.00016	0.00022	0.00029	0.00033
1 700					0.00002	0.00002	0.00003	0.00004	0.00006	0.00007
1 800					0.00	0.00000	0.00000	0.00000	0.00000	0.00000
1 900						0.00	0.00000	0.00000	0.00000	0.00000
2 000							0.00	0.00000	0.00000	0.00000
2 100								0.00	0.00000	0.00000
2 200									0.00	0.00000
2 300										0.00

$L_N(x)$ is the probability that the load plus the capacity on outage equals or exceeds the given value x when the generating system through the Nth unit out of G total units is being considered.

Thus, $L_1(500)$ is equal to 0.84. As a further example, $L_9(1300)$ is equal to $L_8(1300)$ times the probability of unit 9 being available (0.01148 times 0.95, or 0.01091) plus $L_8(1200)$ times the probability of unit 9 not being available (0.02787 times 0.05, or 0.00139). $L_9(1300)$ is the sum of probabilities for the above two situations, or 0.01230.

The energy generated by each unit is determined as follows. For unit 1, the original load duration curve is used, as forced outages of any units in the system do not affect unit 1's observed load. The generation requested by the system from unit 1, excluding unit 1's forced outage time, is the area under $L_0(x)$ over the range of 0 to 200 MW(e) (unit 1's position in the loading order) times the number of hours in the period (8760). From Table 6.XV, $L_0(x)$ is 1.0 over this range, which means that unit 1 is called upon to generate as many kW·h as it can. This is obviously the case as 200 MW(e) is less than the minimum load (400 MW(e)) during the year (practical constraints concerning loading such as spinning reserve are ignored in this example). Thus, the expected capacity factor for unit 1 is p_1, 0.80, and the annual generation is $0.8 \times 1.0 \times 200$ MW(e) $\times 1000$ kW(e)/MW(e) $\times$ $\times$ 8760 h = 1.4016×10^9 kW·h.

The energy generated by unit 2 is determined by examining $L_1(x)$ in Table 6.XV. Unit 2's position in the loading order is between 200 and 400 MW(e), and the values of $L_1(x)$ in this range are over 1.0. Since unit 2 also has a forced outage rate of 20%, the expected generation from this unit is also 1.4016×10^9 kW·h.

The fraction of time that unit 3 is called upon to generate depends on the actual load and the forced outages of units 1 and 2. Therefore, $L_2(x)$ in Table 6.XV is the appropriate ELDC to use. The area under $L_2(x)$ over the range 400–600 MW(e) is 168 MW(e)[11], and therefore the energy unit 3 would generate, without considering its own forced outages, is 1.4717×10^9 kW·h. The forced outages of unit 3 are accounted for by multiplying by 0.9, so the expected generation for unit 3 is 1.3245×10^9 kW·h.

In this way, $L_N(x)$ is used to determine the expected energy generation for the N+1 unit. The results for all nine units are shown in Table 6.XVI. Also shown is the expected unserved energy, which can be determined by subtracting the sum of the generation from the original energy demand. The unserved energy is greater than 0.0 if the generating system is made up of generating units with non-zero forced outage rates. That is, there is always a probability, usually very small, that combinations of random forced outages and loads will result in some demand not being served. The total energy demand is 5.2998×10^9 kW·h, and the total expected unserved energy is 0.0105×10^9 kW·h, or approximately 0.2% of the original demand.

The expected unserved energy may also be calculated by determining the area under $L_9(x)$ beyond the system installed capacity and multiplying by the number of hours in the period. This is a good way to check the previous calculation as both methods should give the same value for expected unserved energy. In this case, the expected unserved energy (EUE) is also 0.0105×10^9 kW·h.

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[11] Assuming linear relationships between points, the area under $L_2(x)$ for $400 \leqslant x \leqslant 600$ is 100 MW(e)·(1.0 + 0.872) $\frac{1}{2}$ + 100 MW(e) (0.872 + 0.616) $\frac{1}{2}$ = 168 MW(e). Multiplying by 8760 hours and converting from MW(e) to kW(e) gives 1.4717×10^9 kW·h.

TABLE 6.XVI. EXPECTED GENERATION FROM INDIVIDUAL UNITS

Unit	Expected values: Unit capacity factor	Expected values: kW·h/a ($\times 10^9$)
1	0.800	1.4016
2	0.800	1.4016
3	0.756	1.3245
4	0.419	0.7342
5	0.224	0.1961
6	0.134	0.1174
7	0.073	0.0641
8	0.038	0.0334
9	0.019	0.0164
Expected total generation		5.2893
Energy demanded (from Table 6.XIII)		5.2998
Expected unserved energy (by subtraction)		0.0105

6.5.6. Operation

Several characteristics of an operating generating system can be dealt with in various ways to make the probabilistic simulation more realistic. This subsection discusses some of the more common characteristics.

6.5.6.1. Scheduled maintenance

The simplified example in the previous section did not consider scheduled maintenance. The most desirable way to treat scheduled maintenance is to perform a probabilistic simulation for a relatively short period, such as a week or two, so that units scheduled for maintenance can be removed from the generating system for the appropriate periods. Since maintenance is not random, it is incorrect to treat maintenance as if it were a forced outage. Treatment of maintenance as forced outages does not give the system credit for the maintenance schedule, which presumably was prepared with consideration of reliability and cost tradeoffs. However, in long-run optimizations, such as in WASP, it is not usually practical to carry out all the probabilistic simulations on a weekly or biweekly basis. One method is to derate the capacity of the unit in those periods during which maintenance is expected. For example, for a problem having only four periods per year (13 weeks each), a 50 MW(e) combustion turbine with two weeks of annual scheduled maintenance would have a capacity of only 11/13 × 50, or 42.3 MW(e), in the period when the maintenance is expected. The forced outage rate is not affected by this approximation. Explicit treatment of maintenance (short simulation periods) is preferable to derating for maintenance whenever possible.

6.5.6.2. Instant on-off assumption

The two-state approximation for operating generating units assumes the unit is either completely forced out or operating at full power. No other possibilities are included when the unit is being called upon to operate. Clearly, this is not a realistic assumption even though equivalent forced outage rate accounts for partial forced outages. For example, when a unit is being loaded after a cold startup, there is a maximum rate at which the unit can approach full power (ramp rate). One way to partially account for the fact that a unit sometimes operates at partial power without having a forced outage is to split the unit into more than one block of capacity. These blocks can then occupy non-consecutive positions in the loading order. This is discussed further in the next paragraph.

6.5.6.3. Blocking of generating units

A more reasonable representation of the operation of the generating system can sometimes be achieved by splitting the generating units (or at least the major units) into two or more blocks of capacity. One explanation of why such a representation is more reasonable than single-block loading is that it is sometimes more economical from the point of view of the utility system to reduce the output from a base load unit than to shut down a unit with higher variable cost [7]. It is important that the average heat rates for each block are calculated to represent correctly the actual thermal energy required for generation from that block. In the probabilistic simulation of multiblocked units, the first block of a particular generating unit encountered in the loading order is treated as if it were a separate unit. However, when the second block of that unit occurs in the loading order, the effects of forced outages of the first block on the equivalent load duration curve (ELDC) must be removed. Thus, the recursive formula for $L_N(x)$ is used to calculate $L_{N-1}(x)$, where the unit removed is the first block of the unit considered. Then the energy for the second block is determined from that ELDC because outages of the first block of a unit do not affect the energy generated by the second block. That is, when a unit goes on forced outage, the entire unit is forced out (the equivalent full forced outage rate is used to account for partial outages). Next, the effect of a single unit consisting of the combined capacities of the two blocks is used to generate the new ELDC. If this approach were not used, the separate blocks would appear to the system as if they were individual units. This would result in incorrect estimates of energy generated not only for the unit in question but all units following in the loading order. In addition, the reliability calculations would be in error; for example, the system reliability consequences of a 1000 MW(e) unit with a 10% forced outage rate are far different from ten 100 MW(e) units, each with a 10% forced outage rate.

6.5.6.4. Technologies with fixed energy supply

Hydroelectric energy is often available only to a limited extent, and capacity factors for hydroelectric units are therefore fixed to the degree that water availability can be predicted. Since operating costs of hydroelectric plants are generally very low, simply placing a hydroelectric unit in a probabilistic simulation would generally call for more generation than is available. Therefore, various approximations are used to represent hydroelectric units or other types of unit with a fixed energy supply. The WASP model simulates system operation of hydroelectric capacity by dividing total hydroelectric capacity into two general categories. The base hydroelectric is that portion of total capacity that is expected to generate continuously at full power during a simulation period (this could represent the minimum flow conditions for a system's combined hydroelectric capability). The second portion of the hydroelectric capacity, or peaking hydroelectric, specifies both capacity and energy. The simulation model then loads the peaking hydroelectric in the appropriate position in the loading order so that exactly the right amount of energy is used. This usually means that peaking hydroelectric and a thermal unit share two positions in the loading order. This approximation for hydroelectric plant is reasonable from both the energy and economic points of view for a long-run optimization model. Chapter 8 discusses hydroelectric energy more fully.

Since various types of hydroelectric facilities have different energy storage capability, models must deal with the timing of the capacity and energy availability. The WASP-III model (Chapter 11) has approximations to represent four types of reservoir: run-of-river, daily, weekly and seasonal regulation. The WASP model calculates the base and peak energy for each type of plant based on input values of inflow energy, installed capacity and regulating volume of the reservoir. Different approximations are used for these hydroelectric plants in order to use the base-peak representation described above.

6.5.6.5. Spinning reserve

As discussed in Section 6.3, spinning reserve can alter the economic loading order. Spinning reserve is accounted for in the WASP model by associating a fast spinning reserve capability with the first (base) block of capacity for a generating unit. When the second (peak) block of capacity for that unit is loaded, the generating system's spinning reserve drops by the amount contributed by the base block for that generating unit. A system spinning reserve goal is set depending on the load and/or the size of the largest operating quantity of capacity from a single unit. The economic loading order is followed whenever the system spinning reserve goal is achieved. When the goal cannot be achieved by following the economic loading order, additional base blocks of capacity are loaded to build up the spinning reserve. In this way an approximation to a loading order subject to spinning reserve constraints is obtained. It is important to note that the production cost for the generating system can be significantly increased by imposing severe spinning reserve constraints. In general, the economic loading order results in loading the peak block of a generating unit immediately after the base block. This is because the average incremental heat rate for the peak block is usually lower than the average heat rate for the base block, and the peak block is therefore more economic to load than the base block.

6.5.6.6. 'Must-run' units

Some generating units cannot be shut down overnight or must continue operation because of area stability or for other reasons. Such 'must-run' units can be accommodated in a production cost simulation by specifying the loading order or at least specifying exceptions to strict loading order rules, such as the economic loading order or the economic loading order subject to spinning reserve constraints.

6.5.6.7. Firm purchases and sales

Utilities often have arrangements with neighbouring utilities for exchanges of energy at times beneficial to both parties. For example, the marginal fuel in winter for one utility might be coal at the same time when a neighbouring utility is using oil as marginal fuel. In such a case it may be advantageous for the second utility to buy power from the first. Accounting for such arrangements in production cost models through modification of the load duration curve is usually the preferred method. Purchases and sales are usually not constant around the clock, so the modifications must be to the chronological load data, before formation of the load duration curve. To determine which generating units are providing energy for sales, two production cost simulations are needed: one with the sales and one without. The generation devoted to the sales can then be determined by subtraction. A less preferred approximation for treating purchased power is to use a fictitious generating unit.

6.5.6.8. Emergency inter-ties

Utilities often have sufficient interconnection of transmission systems with neighbours for a significant quantity of emergency power to be available in addition to firm purchases or sales and economy purchases or sales. Thus, the reliability of the generating system can be significantly improved if this emergency inter-tie power is included. Actual LOLP or unserved energy may be much lower for the interconnected system than for the isolated generating system. One way to account for this effect in a system expansion analysis is to include very reliable capacity with very high operating costs so that it occupies the final position in the loading order. An alternative is to analyse the isolated system and account for the effects of inter-ties through unserved energy cost or by changing LOLP, reserve margin, or other reliability constraints accordingly.

6.5.6.9. Energy storage

Energy storage as used here excludes standard hydroelectric units. A pumped storage plant with an upper and lower reservoir and which requires pumping energy from the system is one example of an energy storage technology.

Technologies involving energy storage present a complication for models using load duration curves rather than chronological load data. The basic problem is proper representation of the timing of the energy drawn from storage and the timing of the generation that is stored. Adjacent points on a load duration curve could represent an hour from the middle of the night on a weekday and a daytime hour at the weekend. A generator based on daily storage could be expected to be storing energy at one point of the load duration curve and generating at the next. In general, however, the use of stored energy can be expected at times of relatively high loads and the collection of stored energy can be expected at times of relatively low loads. This reasonable assumption allows approximations for energy storage to be made (this was used in WASP-II; the present version, WASP-III, does not explicitly include storage options). Caution must be exercised, however, because the assumption that all storing (pumping for pumped storage) occurs at the absolute lowest loads in a time period and that all generation occurs at the highest loads in a time period may result in an overestimate of the benefits of adding a storage technology to a generating system, especially if long time periods (e.g. seasons) are used. Similarly, for existing storage generators, such an approximation can lead to more operation than is feasible and, therefore, to an underestimate of the operating costs.

6.5.7. Accuracy tradeoffs and recent innovations

Needless to say, there are tradeoffs between accuracy and computer time in carrying out the probabilistic simulation. In the more complicated simulations there may be dozens of generating units, each with multiblock representation. The most desirable situation for a probabilistic simulation would be to have:

(a) A time interval less than or equal to the shortest non-zero scheduled maintenance period for any generating unit in the system;

(b) Separate simulation of several hydroelectric possibilities, e.g. dry year or normal year;
(c) Multiblock representation of units;
(d) Appropriate treatment of spinning reserve and economic dispatch;
(e) Accurate representation of the ELDC so that faith can be placed in capacity factors of small units and reliability results.

Clearly, when analysing thousands of possible system configurations over long planning horizons, compromises must be made. For example, as already mentioned, WASP treats scheduled maintenance using the derating technique.

Analysts must examine each individual problem to determine what approximations are appropriate. For long-run expansion analysis, reasonable approximations may result in large errors for the operating costs or system reliability for a particular short time period. One approach to this problem is to examine the best solutions from the long-run models in detail using more restrictive assumptions or a more detailed production cost and reliability model.

Because applications of probabilistic simulation have been reasonably successful in representing electric generation systems for planning purposes, significant effort has focused on methods for improving accuracy and/or reducing computing time while maintaining acceptable accuracy. Numerical representation of the ELDC can lead to errors after numerous convolutions and deconvolutions because of truncation and round-off errors. WASP uses a Fourier series to represent the ELDC. However, inaccuracies can creep into the calculations, depending on the number of Fourier coefficients used, and computation time is still significant [22].

A recent innovation is representation of the ELDC using analytical representations (polynomial expansions) [23, 24]. The cumulant method, or method of moments, using a Gram-Charlier or Edgeworth expansion, significantly reduces computational effort, but some questions remain concerning accuracy in various circumstances [25, 26]. As further experience has been gained, methods to overcome some of these inaccuracies have been developed [26]. Other innovative approaches and improvements in existing techniques for calculating production costs and reliability will undoubtedly appear as analysts continue to study this topic (Appendix C reviews some recent developments in more detail).

6.6. COMPARISON OF PRODUCTION COST ANALYSIS AND SCREENING CURVES

In the initial stages of a generation expansion study, many more alternatives are often available than can be reasonably considered in detail. Screening curves provide a simple method for eliminating from further consideration those alternatives which are significantly less economic. The screening curve method only provides rough approximations and is not appropriate for evaluations requiring reasonable accuracy.

Production cost analysis is described in Section 6.5 as a method designed to handle details of system operations. The concept of screening curves is described in this section as a simplified approach for quick examination of system optimization strategies. Neither method satisfies all the desired properties for system optimization studies, but both methods are useful at certain stages of expansion studies. Screening curves are most appropriate for initial scoping efforts, while production cost simulations are more useful for detailed examination of operating costs and for calibration tests of simplified representations.

6.6.1. Screening curve method

The screening curve method combines simplified representations of generation costs and system load projections in order to approximate the optimum mix of generating technologies. The basic approach is to construct cost curves for each technology and then to match the points of intersection with corresponding load points to determine the most cost-effective operating regimes and capacities for each technology. The technique captures the major tradeoffs between capital costs, operating costs and levels of use for various types of generating capacity in a system. It recognizes, for example, that the low capital/high fuel cost characteristics of combustion turbines are preferable to high capital/low fuel costs of nuclear units for applications requiring small amounts of annual generation. Most important, this method requires only minimal technical and analytical inputs while it quickly provides simplified estimates of optimal technology mixes.

It is important to be aware of the limitations associated with screening curves. Screening curve analysis is not an adequate substitute for detailed production cost or expansion planning analysis. Important factors such as forced outages, unit sizes and system reliability are not treated directly with screening curves [27]. The limitations of screening curves, and methods for dealing with them, are discussed with the examples and comparisons in this section.

The screening curve method expresses the total energy production cost for a generating unit, including all capital and operating expenses, as a function of the capacity factor for the period of interest.(Annual time periods are generally used for screening curve studies, but other period lengths are possible. Implications for various time periods are discussed later.) The following equation defines the cost curves of interest for this approach:

$$\text{Total cost} = (\text{annualized fixed costs}) + (\text{variable costs} \times \text{capacity factor} \times \text{hours per year})$$

Figure 6.14 illustrates a simple case where annualized fixed costs are represented by the y-axis intercept, and variable costs (including fuel and variable O&M costs) are shown as the slope of the line. The combined costs are expressed per unit of capacity (\$/kW·a) so variable costs (expressed per kW·h) must be multiplied by

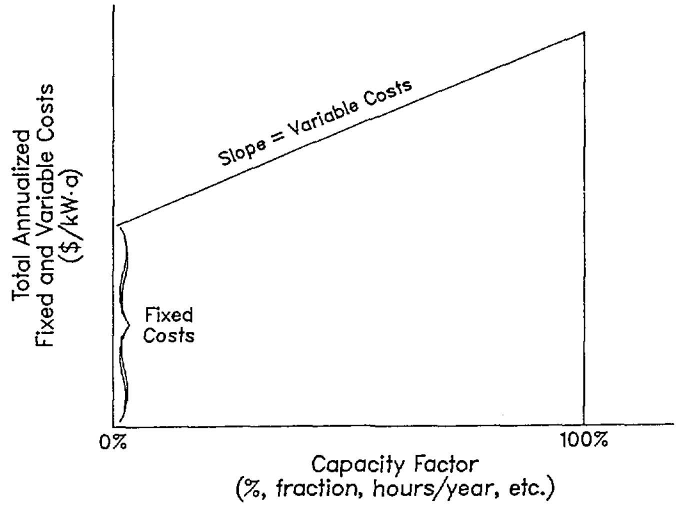

FIG. 6.14. Cost representation for screening curve method.

the appropriate capacity factor and hours per year prior to the addition by fixed costs.

To further demonstrate this step in the screening curve approach, a hypothetical case is given below with five potential generating alternatives. Cost curves are derived and then combined with a cumulative load curve to estimate an optional plant mix.

First, assume that the cost data shown in Table 6.XVII are representative of the choices for system capacity. Since a period length of one year is used for this example, the capital portion of fixed costs must be annualized. Assume that the capital recovery factor is 5% (no inflation). Total fixed costs can then be obtained by multiplying the capital costs by 0.05 and summing the result with fixed O&M costs. Variable costs are derived by multiplying average heat rates by fuel costs and then summing with variable O&M costs[12]. Table 6.XVIII shows the costs that result from these manipulations. The cost characteristics contained in Table 6.XVIII can be diagrammed for comparison as shown in Figure 6.15, which indicates that two of the hypothetical options are not competitive at any point in the range of capacity factors. The 400 MW oil unit and 200 MW coal unit display higher combined costs than the alternatives. The other three alternatives have distinct ranges of annual operation for which they provide the least-cost energy source.

Boundary points for each range can be found by selecting the linear cost functions for two technologies and solving for the capacity factor which results

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[12] Fuel cost calculations require minor changes in units to coincide with the mills/kW·h used for variable O&M costs.

TABLE 6.XVII. HYPOTHETICAL COST DATA

Technology/ size (MW)	Capital cost (\$/kW(e))	Fixed O&M (\$/kW·a)	Variable O&M (Mills/kW·h)	Annual ave. heat rate (10^3 J/kW·h)	Fuel cost (\$/10^9 J)
Coal/600	752	16.20	0.21	10021	1.42
Coal/200	1054	35.64	0.46	10148	1.42
Oil/400	680	15.44	0.20	9842	4.74
Nuclear/1000	1488	13.93	0.18	10807	0.57
Gas turbine/50	160	5.40	0.69	14586	5.92

TABLE 6.XVIII. FIXED AND VARIABLE COSTS FOR HYPOTHETICAL EXAMPLE

Technology/size (MW)	Fixed cost (\$/kW·a)	Variable (Mills/kW·h)
Coal/600	53.80	14.44
Coal/200	88.34	14.87
Oil/400	49.44	46.85
Nuclear/1000	88.33	6.34
Gas turbine/50	13.40	87.04

in equal costs. For example, the point at which total costs are equivalent for gas turbines and 600 MW coal units is found by:

$$\text{Total cost (gas turbine)} = 13.40\ \$/\text{kW}\cdot\text{a} + \frac{87.04\ \text{mills/kW}\cdot\text{h}}{1000\ \text{mills/\$}}\quad 8760\ \text{h/a}\cdot\chi$$

$$\text{Total cost (600 MW coal)} = 53.80\ \$/\text{kW}\cdot\text{a} + \frac{14.44\ \text{mills/kW}\cdot\text{h}}{1000\ \text{mills/\$}}\quad 8760\ (\text{h/a})\cdot\chi$$

where χ is the capacity factor expressed as a fraction of time. Equating the two cost totals and solving for χ yields the following result:

$$\chi = \left(\frac{53.80 - 13.40}{87.04 - 14.44}\right)\left(\frac{1000}{8760}\right) = 0.0635$$

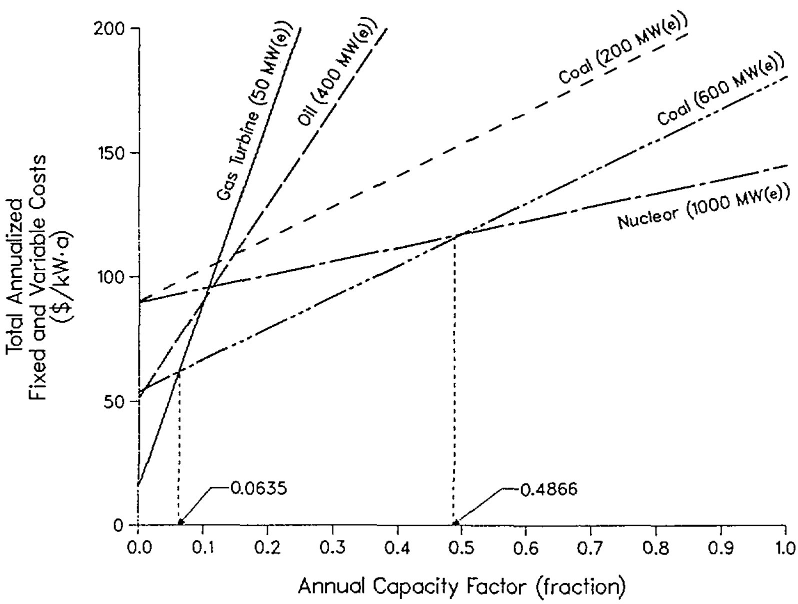

FIG. 6.15. Graphic comparison of fixed and variable cost characteristics for hypothetical example.

Thus, for capacity factors between zero and 0.0635, gas turbines provide the cheapest source of energy. Similarly, the critical point between 600 MW coal units and 1000 MW nuclear units is at a capacity factor of 0.4866. Tradeoffs between fixed and variable costs become apparent through these examples and the graphic procedure.

The diagram in Figure 6.15 is useful for determining optimal operating ranges[13] for generating options, but for system expansion studies, optional mixes of capacity are of greater interest. The second step in screening curve analysis provides the necessary translation.

As shown in Figure 6.16, points of intersection from the cost curves are mapped directly onto the cumulative load duration curve. The two non-competitive technologies have been omitted from this illustration. Assume that the load curve can be represented by the following equation:

$$Y = 1.0 - 2.68697X + 11.21611X^2 - 23.72454X^3 + 21.74757X^4 - 7.25159X^5$$

[13] The operating ranges are only approximations to optimal modes of generation. Factors which are discussed later in this section interfere with precise determinations of optimal conditions.

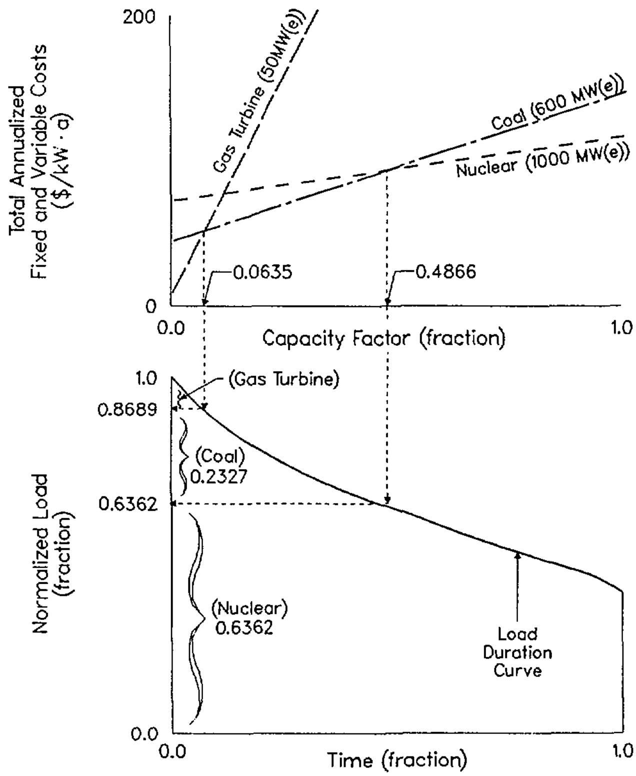

FIG. 6.16. Determination of plant load factor by screening curve method.

where Y is the normalized load and X is normalized time. Substituting previously determined capacity factors into this equation provides the following points of intersection with normalized loads:

for $X_1 = 0.0635$ $Y_1 = 0.8689$

$X_2 = 0.4866$ $Y_2 = 0.6362$

Simple subtraction is used to determine the relative intervals between these points of the vertical axis. Since the vertical axis corresponds to load magnitudes, the ranges derived for each technology are interpreted as if they were relative capacities. Table 6.XIX shows the results.

Relative capacity mixes are estimates rather than absolute capacities. If no forced outages were associated with generating units, the absolute load duration curve (expressed in MW rather than fractions of peak load) could be used directly to obtain the number of megawatts required for each technology. Instead, reserve margin and other factors must be considered.

TABLE 6.XIX. RESULTS OF SCREENING CURVE ANALYSIS

Technology/size (MW)	Implied best capacity factor range (fraction)	Normalized load range (fraction)	Implied best mix of capabilities (fraction)
Gas turbine/50	0.0–0.0635	0.8689–1.0	0.1311
Coal/600	0.0635–0.4866	0.6362–0.8689	0.2327
Nuclear/1000	0.4866–1.0	0.0–0.6362	0.6362

6.6.2. Comparison of screening curves with production cost analysis

The factors affecting energy production from generating units in a system were described in Section 6.3. Methods of dealing with these factors in production cost analysis are discussed in Section 6.5. The object of Section 6.6 is to show how screening curves and production cost methods differ with respect to these factors.

The following topics pose potential problems for screening curve applications.

Unit availability (forced outage rates and maintenance)
Discrete unit sizes
Existing capacity
Unit dispatch factors (minimum load, spinning reserve, startup costs, variable heat rates)
System reliability
Dynamic factors (load growth, economic trends)
Method of interpreting long-term sequence of short-term results

The problem of recognizing outage effects for generating units was alluded to in the example given in Section 6.6.1. If units were perfectly reliable and had no maintenance requirements, then the optimal capacities could be obtained direct (in MW) from an absolute load duration curve. (Even in this case the other limitations of screening curves would distort the optimal solution.) Total system capacity would just equal the system peak load. However, since scheduled and forced outages do occur, total installed capacity must include a reserve margin. The magnitude of reserves may be determined in many ways including fixed criteria, system reliability analysis or criteria based on the largest generating unit. Regardless of the method for determining reserves, capacities derived from the screening curve approach must be increased sufficiently to cover the additional requirement.

One approach is simply to maintain the relative mix determined by screening curves but increase the capacity in each category sufficiently to meet a predetermined reserve. This method guarantees that a specific reserve criterion can be met but does not ensure that it is accomplished economically. A technology originally screened to operate with capacity factors between 20% and 30% might be required to operate between 25% and 40% owing to outages of other units. The shift in operation changes the complexion of the original screening curve solution and means that some of the capacity assigned to this technology should probably come from another source better suited to the higher capacity factor.

In contrast, production cost methods usually treat the effects of planned and unplanned outages explicitly. Provisions are usually made to simulate maintenance schedules by calculating production costs at short enough intervals to exclude entirely the units being maintained in each period. The use of short time intervals is not very helpful in conjunction with screening curves because of difficulties in interpreting different capacity mixes that would result for multiple time periods in an annual simulation. Optimal capacity mixes for individual periods are not very useful when plant lifetimes are on the order of 30 years or more. The objective of long-term system optimization is to determine technology mixes that provide minimal costs in the long run, even though costs for a particular year or a period within a year may not be the lowest possible.

Similarly, forced outage rates are often treated explicitly in production cost analysis but not in the screening curve approach. Many production cost simulations treat forced outages probabilistically so that the energy generation assigned to each unit is carefully weighted by the expected outages for that unit as well as for combinations of outages for other units (Section 6.5 describes the methods in greater detail). As previously mentioned, screening curve methods must approximate the effects of forced outages by adopting a specific reserve requirement (usually a fixed percentage of peak loads). This requirement must then be allocated among the categories of generating options by some kind of heuristic algorithm.

To summarize the approaches to planned and forced outages, production cost methods generally provide accurate estimates of the cost effects due to outages, while screening curves tend to distort the cost effects and consequent implications for optimum capacity mixes. Nevertheless, some insights into capacity optimization are yielded by screening curve methods, whereas production cost simulations only deal with prespecified system configurations. Production cost techniques provide only limited insights into the system optimization problem.

Discrete unit sizes present another difficulty with screening curves. The procedure operates over a continuum of capacity factors and capacity mixes. The method is very unlikely to produce results that directly translate into integer multiples of available unit sizes. The example given in Section 6.6.1 can be used to demonstrate this point. If the total capacity requirement is 2000 MW, then the proportions of capacity would translate into 262.2 MW of 50 MW gas turbines, 465.4 MW of 600 MW coal units and 1272.4 MW of 1000 MW nuclear units. Clearly,

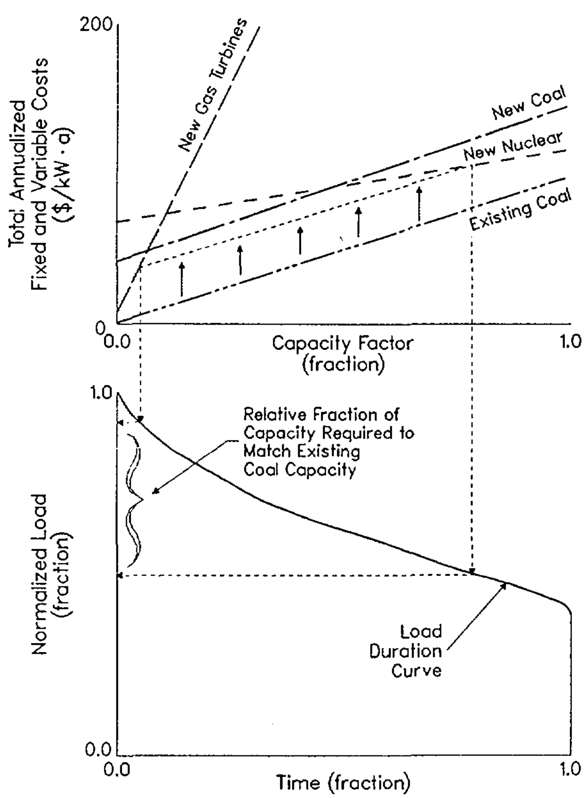

FIG. 6.17. Method for treating existing capacity by screening curve.

some adjustments would be necessary to obtain a system composed of allowable unit sizes. The optimal strategy for shifting amounts of capacity or overbuilding in selected categories of generation is not likely to be apparent for complex systems. Production cost simulations do not have this difficulty as they usually treat specific unit sizes for a predefined utility system.

Screening curve studies also tend to encounter difficulties in treating the effects of existing capacity. The method, as outlined in Section 6.6.1, utilizes cost curves that assume all capacity is new. If, for example, there already exists more capacity of a particular technology than prescribed by screening curves, the original solution must be altered. One method of accommodating existing capacity is illustrated in Figure 6.17. First, a cost curve for existing capacity is included, similar to those for new capacity except that fixed cost components (vertical axis intercept) are omitted. Then, the curve is moved upward, parallel to its original slope, until a position is reached which provides the correct capacity value when mapped against the load duration curve [28, 29].

The approach shown in Figure 6.17 is reasonably straightforward if only one type of existing capacity requires treatment, but may become much more difficult with two or more existing technologies. If there are areas of overlap for existing capacity adjustments, many interactions may be necessary to obtain the correct capacities for each option. As the cost curve for one technology is adjusted upward, it can effectively reduce the capacity factor range and corresponding capacity already calibrated for another technology. Analytical solution methods are possible in treating the more complex screening curve problem [28, 29] but the primary advantage of screening curves (their simplicity) is reduced and other problems discussed in this section remain unsolved.

Characteristics of power plants affecting unit dispatch priorities are difficult to treat with screening curves. Production cost techniques are often designed to treat the effects of minimum unit load restrictions, startup costs, variations in heat rates (with changes in output), and spinning reserve requirements. Each of these characteristics influences operating costs and the relative attractiveness for capacity choices. However, the simplified representations preclude direct treatment of the dispatch factors.

System reliability encompasses a broad range of concepts, which are discussed in detail in Chapter 7. The implications for screening curves are briefly mentioned here in order to characterize this simplified approach in perspective with system planning. It has already been pointed out that there are difficulties in dealing with unit availabilities with screening curves. Even simple reserve margins are difficult to allocate efficiently between technology options but, more important, reserve margins are being rapidly replaced by more comprehensive reliability criteria for system expansion planning. In many cases, reliability calculations are included directly with production cost simulations since many of the probabilistic concepts and treatments are analogous.

Screening curves, on the other hand, are rather insensitive to the key parameters affecting system reliability. Unit sizes, forced outage rates and maintenance requirements are of particular interest since they directly influence reliability but are not recognized in screening curve analyses. The effects of unit sizes on fixed and variable costs are treated with reasonable accuracy in the screening curve approach, but the effects on reliability are omitted. Not only do two 100 MW units have different cost characteristics from a single 200 MW unit; they also have different implications for the system's ability to meet loads in view of forced outages and scheduled maintenance. Differences such as these are not always apparent in screening curve results.

Screening curves are most suitable for examining conventional generating alternatives such as steam units fuelled by nuclear, coal, oil and gas sources. Other options such as hydroelectric pumped storage and wind generation are not as easily accommodated. While conventional technologies are usually available except for planned outages and unexpected failures, other technologies may have distinct patterns or schedules of availability. Pumped storage, for example, cannot be readily optimized with the screening curve method that uses cumulative load duration curves. The availability of pumped storage generation depends on time-of-day and seasonal patterns that reflect overall system operations in response to loads. Similarly, hydroelectric and wind generation are both characterized by constraints on the timing and quantity of energy availability. Such constraints are not readily treated with screening curve procedures.

The final difficult area to be identified involves dynamic factors such as load growth, long-term versus short-term optimal solutions, and recognition of time variations in the optimal capacity mix. Chapter 10 discusses methods for dealing with these and other complex issues in detailed long-range planning models. Production cost models do not encounter these problems since they are not intended to provide optimal expansion strategies but only production costs (and perhaps reliability calculations) for predefined configurations. Screening curve methods are intended to be applied to long-term expansion problems, so load growth and the other dynamic factors mentioned above are of concern.

As load growth and other system changes occur with time, the optimal plant mix also changes. Difficulties arise in (a) selecting an appropriate time horizon for basing capacity expansion plans and (b) finding a choice of technologies and construction schedule that minimizes costs for the entire planning period. The first problem is encountered both in the screening curve approach and in long-term optimization models. Short time horizons (such as a few years) tend to favour low capital/high operating cost technologies while allowing more immediate responses to system trends. However, after a moderately long period (15 to 30 years, for example) the system composition may have diverged significantly from the long-term optimal. Uncertainties in long-term projections need to be balanced against potential long-term cost savings.

The second problem is particularly difficult for the screening curve approach if the planning horizon covers a substantial period of time. In expansion analysis, it is important to account not only for load growth but also for the time value of money. The optimum plant mix will change from one period to the next (year to year if annual periods are used) and the differences may be difficult to reconcile. Detailed methods described in Chapter 10 recognize this problem and use a variety of simulation techniques to incorporate dynamic factors and time horizons. Screening curves are more restrictive since they produce 'snapshot' estimates of capacity mixes.

6.6.3. Summary

In spite of the drawbacks identified for screening curve analysis, the technique provides a useful tool when properly applied. Screening curves are especially useful as aids for narrowing the range of possible technology alternatives that need to be considered in more detailed analysis. A major difficulty with long-range optimization models is that they quickly become unmanageable as the number of options increases. Screening curves provide a straightforward and rapid method for determining which technologies are potentially competitive with other energy sources. The rough estimates of capacity mix also provide useful guidelines for scoping and examining detailed simulations.

In comparison with production cost analysis, screening curves do not treat many of the important factors that affect generation costs. Production cost methods can provide reasonably accurate estimates of costs as affected by unit performance parameters, cost characteristics and complex operating considerations. However, computational requirements of production cost calculations preclude their full use in comprehensive long-term optimization models. As such, the screening curve method is especially useful for reducing the excessive size of expansion studies in the earlier stages of investigation, while production cost techniques are more useful in the later stages of expansion analysis when cost assumptions and approximations have to be reviewed for accuracy.

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Chapter 7

GENERATING SYSTEM RELIABILITY

In this chapter, various technical approaches to measuring the reliability of generating systems are outlined and some key parameters for calculating this reliability described. Actions that utilities can take to minimize the consequences of outages are examined for different types of outages. Finally, the problem of placing a 'value' on reliability is conceptually developed, and results of efforts in many countries to quantify this value are summarized.

7.1. MEASURING THE RELIABILITY OF GENERATING SYSTEMS

Reliability is important in long-range electric system expansion planning. Reliability concepts are required to establish target reliability levels and to consistently analyse and compare the future reliability levels of alternative expansion plans. The overall goal of electric system planning is, broadly, to provide acceptable levels of service reliability to customers at the lowest possible cost, where a reliable generation system is typically characterized as having sufficient redundancy for random equipment failures not to be perceived by the customers as service interruptions.

Reliability criteria have traditionally been used as constraints in long-range capacity expansion models optimizing an economic objective (e.g. minimizing total discounted system costs subject to a specified reliability criterion). This approach to expansion planning does not, however, allow reliability-cost trade-offs, i.e. it does not take into consideration the trade-offs between economic factors and different levels of reliability inherent in capacity expansion planning. Some sophisticated planning models, such as WASP-III (see Chapter 11), allow reliability criteria to be incorporated directly into the objective function and/or be used as system constraints. Such treatment of reliability allows a more realistic representation of the planning process.

In the context of overall systems, the supply of reliable electric service to customers depends not only on the generating system but also on transmission and distribution systems. Customers may consider a utility system reliable only if it supplies them with the quantity and quality of electricity they desire when they desire it. Therefore, all three of the subsystems (generation, transmission, distribution), which can fail for any number of reasons and at any time, are critical. Historically, however, electric utilities have approached generation, transmission and distribution reliability planning as separate and sequential functions, an approach which is due in part to the considerable complexity of evaluating the reliability of each subsystem. Target goals for overall system reliability are typically established on the basis of historical patterns and practices.

7.1.1. Typical system reliability measures

A large number of reliability indices are currently in use or have been proposed for use in power system planning. A reliability index is defined broadly to be a quantity that measures and quantifies some aspect of system reliability performance [1]. Such indices may apply to the entire power system, from generation through distribution to ultimate customers, or to only a portion of the system, such as generation. The reliability indices defined in this section measure generating system reliability only and exclude the transmission and distribution systems.

The various reliability indices used in the electric power industry can generally be grouped into two broad categories: (a) *deterministic indices,* which reflect postulated conditions; and (b) *probabilistic indices,* which consider the uncertainty inherent in power system operation. Probabilistic indices permit the quantitative evaluation of system alternatives by taking directly into consideration the parameters that influence reliability, such as the capacities of individual generating units and the forced outage rate of each unit. While deterministic indices are more limited, they are popular because their calculation is simple and requires little or no data, and because acceptable values of the indices are well established and benchmarked against historical experience.

Twelve reliability indices are defined in this section[1]. The first three – reserve margin, largest unit and dry year – are deterministic indices, while the remaining nine are probabilistic indices. It is important to recognize that each index has certain strengths and weaknesses and cannot therefore individually provide a complete description of generating system reliability.

7.1.2. Reserve margin (RM)

Reserve margin is a measure of the generating capacity available over and above the amount required to meet the system load requirements. It is defined as the difference between the total available generating system capacity and the annual peak system load, divided by the peak system load, i.e. it is the excess of installed generating capacity over annual peak load expressed as a fraction (or in percentage) of annual peak load. For example, a system with a total installed capacity of 11 500 MW(e), and which experiences a peak load of 10 000 MW, has a reserve margin of 15%. While this deterministic reliability index does not directly reflect system parameters such as generation mix, unit size and forced outage rates, it does provide a reasonable relative estimate of reliability performance when parameters other than reserve margin remain essentially constant.

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[1] The definitions cited are adapted from three primary sources (Refs [1–3]), which can be referred to for more complete and detailed descriptions.

For example, when a system has little diversity in generation types, sizes and forced outage rates, it may be reasonable to assume that maintaining a desired reserve margin, such as 15%, will also maintain an acceptable reliability level. Before probabilistic reliability measures were developed, reserve margin was the primary reliability index used by system planners. Reserve margin is still frequently used in the USA, Canada, and major industrialized countries in Europe as a planning criterion.

7.1.3. Largest unit (LU)

The loss of the largest generating unit method is a reliability measure that provides a degree of sophistication over the standard per cent reserve method by reflecting the effect of unit size on the reserve requirements. The LU method compares the total installed generating capacity less the annual peak system load (i.e. the reserve) with the largest installed units on the system. In contrast to reserve margin, this approach begins to recognize explicitly the impact of a single outage: loss of largest generating unit. For example, a reserve of 1500 MW at the time of peak load (i.e. available capacity minus peak load) for a system with two large 1000 MW(e) units would be expressed as having the largest unit plus half of the second 1000 MW(e) unit. As larger units are added to a system, the per cent reserves for a system are implicitly increased by this method.

7.1.4. Dry year

Sometimes reliability in hydro-dominated systems is defined in terms of required supply during a year with poor hydroelectric availability. This is not really an index but is rather a criterion. The dry year could be defined as the driest year of the available statistical information or a year related to a certain cumulative probability. As an example, in systems with interannual regulating reservoirs, the critical period would be defined not as a year but as a sequence of years (as in Brazil) or, in another case, the dry year is associated with operational criteria of the reservoir.

7.1.5. Loss of load probability (LOLP)

LOLP is a reliability index that indicates the probability that some portion of the load will not be satisfied by the available generating capacity. More specifically, it is defined as the proportion of days per year or hours per year when insufficient generating capacity is available to serve all the daily or hourly loads. LOLP is usually expressed as a ratio of times; for example, 0.1 days per year equals a probability of 0.000274 (i.e. 0.1/365). Target LOLP levels are typically set in the USA and Europe for long-range planning. For example, the target LOLP frequently used in the USA for large interconnected systems is one day in ten years; in European countries, the corresponding standard varies from one day in fifteen years to one day in two and a half years.

LOLP is currently the most widely used reliability index; it is also perhaps the most misunderstood because of the inappropriate use of the word 'probability' in its name. LOLP actually represents an expected duration for all outages rather than the probability of an outage occurring, i.e. LOLP is a unit of time. This situation is further confused by the fact that annual LOLP is sometimes calculated by employing only a series of daily peak loads (365 loads are used to represent one year), while the appropriate calculation of annual LOLP involves using hourly load data (using 8760 loads). Although the results of both calculations may be expressed in units of days per year (hourly data are usually summed and converted to a days per year basis), an LOLP calculated on the basis of 365 daily peaks will always be higher than an LOLP calculated using hourly data because it implicitly assumes that the peak load occurs during all 24 hours of each day.

In an attempt to clarify this confusion, Billinton [4] has defined *loss of load expectation* (LOLE), which is the expected number of days (or hours) per year in which insufficient generating capacity is available to serve the daily (or hourly) peak load. LOLP is then defined as LOLE/N, where N is the number of time increments in the LOLE calculation (N = 365 if LOLE is calculated from daily peak load data and expressed in terms of days, while N = 8760 if LOLE is calculated from hourly load data). In this form, LOLP is correctly expressed as a probability. LOLE and LOLP are still often used interchangeably.

LOLP is not a very meaningful index for hydro-dominated systems. Typically, a measure such as expected unserved energy is more relevant. However, in hydroelectric systems with variable head hydro plants, LOLP does have some merit, as discussed in Chapter 8.

7.1.6. Probability of positive margin (POPM)

This reliability index uses the loss of load probability calculation for only one hour, the peak hour of the year. In contrast to LOLP, however, POPM is expressed as a probability of success rather than the probability of failure. Therefore, a system with a failure probability of 0.005, for example, has a success probability (POPM) of 0.995 (i.e. 1.0 minus 0.005). This index is not as widely used as LOLP and other probabilistic indices.

7.1.7. Expected unserved energy (EUE)

EUE measures the expected amount of energy which will not be supplied per year owing to generating capacity deficiencies and/or shortages in basic energy supplies. Mathematically, EUE (expressed in units of kW·h) is the sum of the probability-weighted energy curtailments caused by capacity deficiencies throughout the year. This index is widely used in Europe where it is one of the most common indices of generation reliability performance. EUE is a very useful index for utilities that utilize energy-limited technologies such as hydroelectric, solar and wind.

7.1.8. Loss of energy probability (LOEP)

This reliability index is conceptually and mathematically related to the EUE index. EUE, as defined previously, is in units of energy and is therefore specific to a particular system and load cycle. In general, EUE tends to be larger for large systems than for small systems, all other things being equal, and is therefore often given as a proportion of total energy demanded. This new index is called the loss of energy probability. Specifically, LOEP is defined as the ratio of the expected amount of energy curtailed owing to deficiencies in the available generating capacity to the total energy required for the system. The LOEP index, generally an extremely small number, is independent of the amount of energy demanded and may therefore be used to evaluate alternatives in a given system as load grows, or to compare systems serving different loads.

7.1.9. Expected loss of load (XLOL)

XLOL indicates the expected magnitude of the unsupplied load, in MW, given that a failure has occurred. It is equivalent to either the expected capacity deficiency divided by the probability of a capacity deficiency, or the EUE divided by the LOLP (or, more correctly, LOLE). XLOL is sometimes called the conditional expected load not supplied (XLNS) because it is a conditional expectation, i.e. it is conditional on the occurrence of a failure.

7.1.10. Emergency operating procedure expectation (EOPE)

The LOLP (or LOLE) index has been generalized and extended to give the expected number of days per year on which various emergency operating procedures such as public appeals for load reduction, voltage reduction and selective load shedding would be required owing to insufficient available generating capacity. These emergency operating procedures usually occur while available generation is still greater than load and they represent utility efforts to forestall greater problems. The distinction between LOLP (or LOLE) and EOPE is significant because, in the hierarchy of utility emergency operating procedures, there are a number of actions which can be taken before any consumers are actually interrupted (see Section 7.2.2). The EOPE index tends to give results that are closer to actual experience than the basic LOLP index.

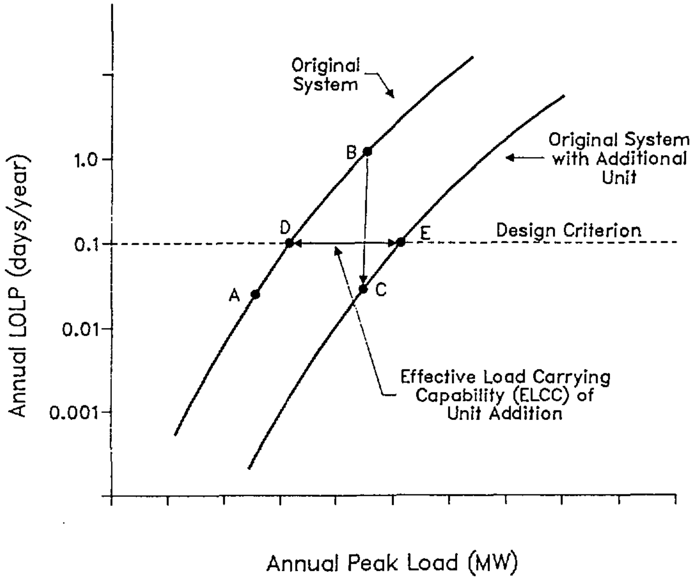

FIG. 7.1. Effective load-carrying capability of unit addition.

7.1.11. Frequency and duration of failures to meet the load (F&D)

The frequency of generating capacity shortage events is defined as the expected (probability-weighted average) number of events per year, while the duration is the expected length of capacity shortage periods when they occur. Frequency and duration indices are always calculated using hourly load information and thus reflect the influences of daily load cycle shape. Furthermore, methods for calculating frequency and duration indices model the generator performance parameters more fully than those models used in calculating LOLP. Thus, frequency and duration indices tend to be more physically meaningful, particularly to customers, than the more abstract LOLP index. However, frequency and duration indices, while conceptually superior to LOLP, have not enjoyed widespread use, partly because of the greater mathematical complexity of the required calculations. The product of the expected frequency of capacity deficiency, and the expected duration of the capacity deficiency, expressed in similar time units, is the loss of load probability, i.e. F X D = LOLP.

7.1.12. Effective load-carrying capability (ELCC)

ELCC is an index designed to measure the worth of a generating unit to a utility system in terms of reliability [5]. The ELCC concept is illustrated in Fig.7.1, which plots annual LOLP versus the annual peak load for a specific

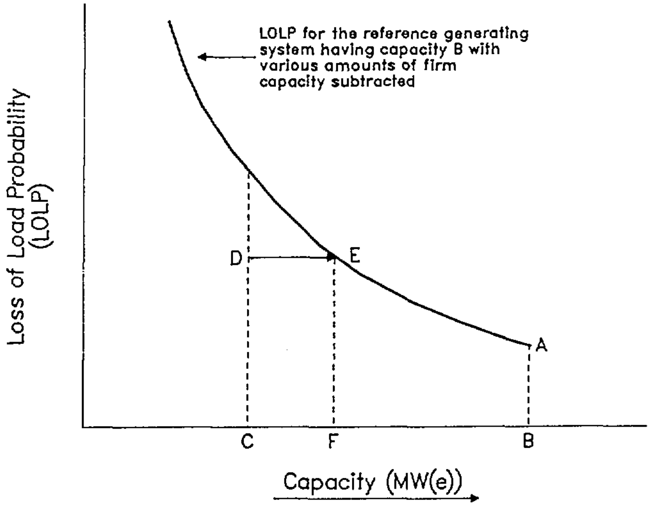

FIG. 7.2. Effect of capacity change on reliability of generating system.

A:	*Original generating system LOLP with B MW(e) of capacity.*
B:	*Capacity of original generating system.*
C:	*Capacity of reduced generating system after a unit with (B−C) MW(e) is subtracted from the system.*
D:	*LOLP of reduced generating system with capacity C MW(e).*
E:	*Point on the firm capacity curve with the same LOLP as D.*
F:	*Capacity corresponding to LOLP of E.*
(B−C):	*Capacity of actual generating unit removed from system.*
(B−F):	*Firm capacity equivalent of the unit with capacity (B−C) MW(e).*

generation system both before and after a new unit is added. The original generating system has an LOLP shown by point A, which meets the design level of reliability indicated (0.1 days/year). However, if annual load growth, for example, increases the peak demand to a point where the generation system cannot maintain the desired 0.1 days/year LOLP criterion, such as point B, then a new generating unit would be needed. The addition of a new unit, however, shifts the curve to the right, as shown in Fig.7.1, and the LOLP decreases from 1.0 days/year (point B) to 0.05 days/year (point C), which is below the desired 0.1 days/year criterion. The ELCC is defined as the difference, measured along the horizontal axis at the design criterion, between the two LOLP versus peak load curves (the difference between points E and D, in MW). This value is a measure of a unit addition's contribution to system capability. As Fig.7.1 shows, this measure is a function of the generating unit's characteristics (size, forced outage rate, maintenance requirements) as well as the characteristics of the power system in which it is operating.

7.1.13. Firm capacity equivalent (FCE)

Like ELCC, FCE is an index designed to measure the worth of a generating unit to a utility system in terms of reliability. In contrast to ELCC, however, the FCE index is measured for a single load. The FCE concept is illustrated in Fig.7.2, which shows the effect on LOLP of dropping a unit out of a generating system. The original generating system with B MW(e) has an LOLP shown by point A. The solid curve represents the increase in LOLP that would occur if various quantities of hypothetical firm capacity were subtracted from the original generating system, where firm capacity is considered absolutely dependable at all times and therefore performs better than real generating units. Each real generating unit in a generating system has a characteristic FCE that is less than its rated capacity. The amount of firm capacity required to bring the system back to its original LOLP is the FCE of the removed generating unit. In Fig.7.2, the FCE of a generating unit with related capacity of (B–C) MW(e) is (B–F) MW(e). A value can be attached to the FCE after consideration of factors such as the characteristics of the specific generating system, the plans and alternatives for system expansion, the inter-tie capability, and the measures that can be taken to reduce load. Once a value has been associated with the FCE, the capacity value of the particular generating unit to the generating system can be estimated.

7.2. IMPORTANT FACTORS IN GENERATING SYSTEM RELIABILITY

To estimate system reliability measures such as those described in Section 7.1, an important set of parameters must be considered. These include some key operating parameters for generating units, characteristics of the system as a whole, and methods used by utilities to moderate the potential effects of generating unit failures. Characteristics of generating units and the system can be used to calculate reliability indices, but the interpretation of such reliability measures depends on the potential mitigation options available to a utility in the event of load loss conditions.

7.2.1. Key parameters in generating system reliability

The reliability of generating systems is influenced by operational characteristics of individual units as they interact with broader system-dependent factors. The key reliability parameters are identified in this section and discussed with regard to the methods and problems encountered in modelling their effects on system reliability. Many of these parameters have already been defined and discussed in Section 6.3 in the context of factors affecting energy production from generating units in a system. The definitions presented in that section are also applicable to the ensuing discussions.

The following description of key parameters is mainly oriented toward a generating system consisting primarily of thermal generating units. Hydroelectric units once again present a somewhat different set of concerns, e.g.:

- They are mechanically reliable but could be energy-limited (insufficient water available during some periods),
- They have variable water inflow and hence the energy that can be generated is variable,
- The net power available can vary with head,
- The operational criteria for the reservoir can affect reliability and costs of the system.

Reliability of generating systems in some hydro-dominated systems is clearly linked with the loss of power in the hydroelectric plants owing to reservoir depletion. Representation of the performance of different reservoirs and the associated hydroelectric plants can be very complex (Chapter 8 covers this in more detail).

7.2.1.1. Generating unit characteristics

The key parameters relevant to generating units include unit sizes and the set of factors that determine unit availabilities. Section 6.3.2 describes unit availability in terms of three contributing elements: forced outage rates, repair times and scheduled maintenance. Forced outage rates in conjunction with unit sizes largely determine the probability of satisfying loads with units that are not on maintenance.

If generating units were perfectly reliable (i.e. no unscheduled outages), there would be no need for system reliability analysis. System expansion could be based directly on load forecasts with allowances for planned maintenance schedules. However, virtually all real generating units have some probability of unscheduled failures. Typical values for forced outage rates tend to range between 3% and 25% depending on the generating technology, unit size and age of plant (see Appendix G for illustrative data). Hydroelectric plants and combustion turbines are sometimes treated as exceptions to this usual range of forced outage rates owing to the extremely reliable performance of hydroelectric units and the potentially high failure rates of combustion turbines under low-usage conditions.

It is important in reliability analysis to recognize that unit sizes directly influence forced outage rates on overall system reliability. For example, a single unit rated at 1000 MW(e) with a forced outage rate of 10% does not result in the same performance as 10 units rated at 100 MW(e) each, all with forced outage rates of 10%. Figure 7.3 demonstrates the difference in probabilities of having a specific number of MW available from each of the two alternatives. Although the expected values of available capacity are the same in each case (900 MW(e)),

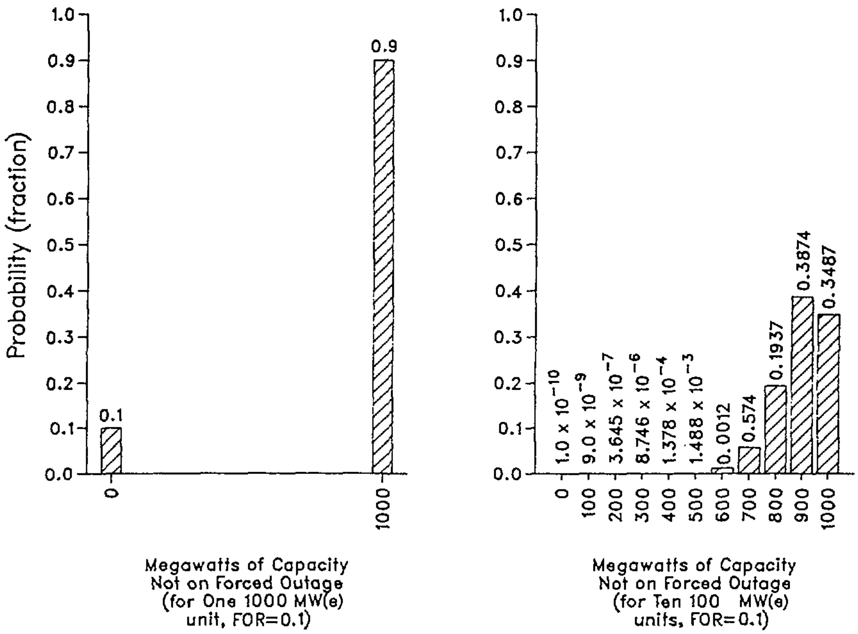

FIG. 7.3. Example of unit size effect on probability of available capacity.

the distributions of capacity are very different. In the single-unit case there is a significant probability (0.10) that none of the 1000 MW(e) will be available for service at a given time. In contrast, the multiple-unit case has a negligible probability (1×10^{-10}) that all of the capacity will be forced out of service at a particular time. This comparison clearly demonstrates that unit sizes have a direct influence on system reliability.

Expected repair times for unscheduled outages are also important for some reliability calculations. Estimates of average outage frequency and duration depend on the length of time required to return a unit to service after an unplanned outage. Repair times for each unit must be specified explicitly for frequency and duration measures. Other reliability indices such as LOLP account for repair times implicitly by using forced outage rates that indirectly reflect average times of repair with probabilities that units are available when called on for service. However, frequency and duration indicators cannot be determined from LOLP calculations unless repair times are incorporated into the analysis.

Planned maintenance requirements for generating units are also important in system reliability. Typical requirements range from a few days for small units to eight or ten weeks for large units (see Appendix G for illustrative data). From the standpoint of system reliability, maintenance periods are important because, once initiated, a unit is usually not available for service until completion. This means that the remaining units (not on maintenance) must be capable of satisfying loads and providing backup power for potential unscheduled outages.

Utilities often know with reasonable certainty the exact number of maintenance days required for each unit. However, for reliability modelling, the maintenance periods must often be approximated according to the discrete time periods used for simulation. Simulation models will often subdivide each year into seasons, months or weeks but usually not into individual days because of the additional computational requirements that occur with larger numbers of time periods. One method of approximation is simply to round off the assigned maintenance requirements to the nearest integral multiple of the simulation time intervals. However, as the simulation time periods are made longer (to keep computational costs reasonable) the distortions introduced by this approach may become unacceptable.

With relatively long simulation time periods, a better approximation may be possible by derating the capacity of generating units according to their maintenance requirements. For example, a 100 MW(e) unit with ten days of maintenance per year would be represented as a 97 MW(e) unit with no scheduled maintenance[2]. This approximation distorts the estimation of system reliability but may prove to be the most reasonable alternative if simulation time periods are much longer than the shortest maintenance period. It is important to consider the trade-offs between higher simulation costs versus improved system representation that occur with shorter simulation time periods.

Refuelling outages and routine maintenance required for nuclear units have similar important effects on system reliability. However, refuelling outages have somewhat less flexibility than other types of planned maintenance. While some slippage in refuelling periods can be accommodated by operating reactors below maximum capacity, the time between refuelling is relatively fixed. This distinction is important for system reliability since routine maintenance can usually be scheduled during periods of the lowest system loads and can often be postponed in an emergency. Refuelling outages do not offer the same degree of flexibility.

7.2.1.2. System characteristics

In addition to the generating unit characteristics described above, there are system characteristics that affect overall reliability. The maintenance schedule, fuel mix, spinning reserves, load-following capability and inter-ties all influence system reliability.

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[2] Derated capacity in this case is found as follows:

$$100 \text{ MW(e)} \times \frac{365 - 10}{365} = 97 \text{ MW(e)}$$

Planned maintenance has been discussed previously as it pertains to individual units. In an integrated system, maintenance requirements for all units must be carefully scheduled so as to minimize the impacts on reliability and production costs. Typically, scheduling of thermal units is based on system load cycles. If there are major seasonal peaks, efforts are made to avoid scheduling any maintenance during those times in order to have as many units available as possible. The largest thermal units with the longest maintenance requirements are usually scheduled first for periods of the year with lowest loads. Since these units have the greatest impact on reliability, it is desirable to maintain them when they are least needed. Units with shorter maintenance periods and/or less capacity are then scheduled, in decreasing order of impact, for time periods with lowest loads until the total capacity scheduled out in a given period becomes large enough to warrant scheduling some maintenance in periods with higher loads. Maintenance of hydroelectric units is typically scheduled for high-water periods. Alternatively, some utility systems and some simulations may schedule maintenance on the basis of minimizing production costs while satisfying a predetermined reliability criterion in any given period. The schedule that results is likely to differ from that obtained when system reliability is maximized regardless of production costs.

The plant mix of a system affects reliability to the extent that different generating technologies may have different forced outage rates and maintenance requirements, even between units of similar sizes. In particular, hydroelectric facilities generally perform with much higher reliability than fossil-fuelled or nuclear units. Two systems with the same amount of installed capacity and loads can have very different reliability characteristics if the mix of technologies differs significantly.

Spinning reserve and load-following capability of a system are operational parameters that affect system reliability but are not always recognized in reliability models. Chronological simulations are required in order to account directly for the effects of these parameters on system reliability (effects of spinning reserves on production costs can be treated reasonably well without chronological detail). Many utilities employ a spinning reserve criterion which specifies the amount of backup generating capacity kept in readiness for instant dispatch in the event of system emergencies. The higher this criterion, the more likely that loads will be satisfied during unit failures or unexpectedly high loads. Similarly, the greater the amount of load-following capability[3] in a system, the more likely that loads will be satisfied under rapidly changing conditions. Load-following capability is important because load losses can occur during rapid load fluctuations even though ample capacity may be theoretically available. Production costs, as well as reliability, are affected since it may be necessary to dispatch units with higher variable costs but greater load-following capability as a precautionary measure.

[3] Load-following capability refers to the speed at which the power output of units can be adjusted in response to changing loads.

When two or more utilities are interconnected with transmission lines that allow power transfers to take place, the capacity of such links is referred to as inter-tie capacity. Inter-tie capacity affects the reliability of a given system to the extent that it reduces the probability that loads will exceed the total available capacity. This is true for non-peak as well as peak load periods. If inter-tie capacity is available during non-peak hours, the magnitude of outage events (MW of capacity on forced outage) required to cause a load loss becomes even more severe and less likely than if the inter-ties were not available. During peak periods, when even minor failure events might lead to system failure, inter-tie capacity can be especially effective in improving system reliability.

It is important to determine the relative availability of inter-ties during peak and off-peak hours. While the maximum capacity of inter-tie power lines may remain fixed, the generating capacity available for emergencies may be much lower during peak hours if loads tend to coincide between the system requiring power and the system supplying the inter-ties or if firm purchases or sales are already scheduled in those time periods. Since emergency conditions are more likely to develop during peak load periods, it is important to recognize that inter-tie capacity may be least available during periods when it is needed the most.

7.2.2. Utility measures to mitigate outage consequences

This section describes the types of outages that generating units may experience and some measures utilities can undertake to minimize the effects of losing any generating unit. Potential responses by the utility are classified according to the type of outage.

7.2.2.1. Outage classifications

Unavailability[4] of a generating unit, or of part of its capacity, affects a utility's generating system in various ways, depending on the length of outage. For this discussion, outages have been classified as follows:

(1) Scheduled maintenance (planned)
(2) Unscheduled outages
(3) Short- and intermediate-term shutdown (up to one year)
(4) Long-term shutdown (more than one year)
(5) Permanent shutdown
(6) Derating
(7) Delay in commercial operation.

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[4] Unavailability of a generating unit refers to its inability to generate when called upon. The two major components of unavailability are scheduled and unscheduled outages.

These categories are not totally independent of each other, but each has some characteristics of its own, as described below.

A distinction should be made here between outages due to equipment failures (lack of power) and outages due to energy limitations although the equipment is available. Predominantly hydroelectric systems suffer more often from 'energy failures' than from 'power failures', so not all emergency procedures and mitigation strategies discussed in the following sections are relevant for energy-limited hydroelectric systems.

Scheduled maintenance is planned well in advance of the time of shutdown. The schedule for planned maintenance is prepared by examining system reliability, expected production costs, and constraints such as refuelling needs for the nuclear units. Planned overhauls are often arranged to the extent possible in low load seasons, such as the spring and autumn for many utilities in the USA. Typical maintenance requirements for various types of generating units are listed in Appendix G.

Unscheduled outages account for all other periods of unavailability for a generating unit. This category includes *forced outages,* in which the generating unit must be shut down for repair almost immediately after some failure occurs, and *maintenance outages,* in which the maintenance work can be postponed past the next weekend but not from season to season [5, 6]. The duration of unscheduled outages is typically short; for example, the average repair time for forced outages of nuclear units has been estimated to be five days [7].

Short- and intermediate-term shutdowns are considered here to be approximately one month to one year in duration, longer than typical forced outages. The shutdown could result from events such as a severe forced outage, refuelling of a nuclear unit, an order from a regulatory agency to modify or replace equipment, or simply an order to temporarily shut down while a potential problem is studied. Thus, these shutdowns are typically not scheduled in advance but, depending on the circumstances, could involve some forewarning, e.g. from the regulatory agency.

Long-term shutdowns are defined to have durations of more than one year. Outages of more than one year could result, for example, from a need for major repairs, such as the cleaning and decontamination of the Dresden-1 nuclear power plant in the USA.

Permanent shutdowns could result from regulation or from decisions by utilities that retirement is the most economic alternative. The differences from long-term shutdowns include decommissioning costs incurred earlier than expected, unrecovered capital costs and replacement of the capacity in the long term as well as the short term.

Derating of a unit's generating capacity could be required as a result of safety-related analyses, could result from operational difficulties, such as plugging tubes to stop leaks in the steam generator, or could result from the addition of pollution control equipment.

A delay in commercial operation for a nuclear unit can be caused by a regulatory agency, such as the suspension in November 1981 of the low power testing licence for unit 1 of Diablo Canyon in the USA, or from a number of circumstances affecting the utility, such as construction delays, financial difficulties, or lower than expected load growth [8].

7.2.2.2. Mitigation strategies

If a generating unit becomes unavailable, utilities have various options depending on the length of expected outage and the circumstances existing in the utility system. If an outage for a generating unit is anticipated to be of relatively short duration, the only effect may be an increased likelihood of implementing emergency operating procedures, and no additional utility actions are needed. If the outage is anticipated to be of longer duration, a number of additional options become available to the utility. This section briefly reviews the range of options facing a utility after the loss of one or more large generating units.

The available options apply to the outage of any generating unit. Although the responses may not be very different for nuclear and non-nuclear outages, the effects on the utility of nuclear outages and outages for other types of plants have a number of notable differences, such as:

(a) Maintenance of major equipment (e.g. the turbine) for a nuclear unit is usually scheduled to coincide with a refuelling outage. A sudden outage for a nuclear unit would normally not occur propitiously at the time for a refuelling. Thus, changing the maintenance schedule is more difficult for a nuclear unit.
(b) The outage of a fossil-fired unit will have less effect on the production costs for the system than an equivalent nuclear outage because of the higher variable cost for fossil-fired units, i.e. the difference between the variable cost of the replacement generation and nuclear costs is larger, and the increase in expenses is greater for nuclear outages on a kW·h basis.
(c) Nuclear units generally have greater capacity than other types of unit. Therefore, the reliability of the generating system is more likely to be affected by the loss of the nuclear unit(s).
(d) A generic shutdown for nuclear units is more likely than for other units. (A regulatory agency could require all reactors of a specific type to be temporarily shut down for modifications.) It would be less likely to lose more than one fossil-fired or hydroelectric unit of the same type at the same time.

TABLE 7.I. TYPICAL EMERGENCY OPERATING PROCEDURES [1, 9]

Utility action[a]	Typical effect
Bypass plant pollution control equipment	Increase available generating capacity by a small amount
Switch from economic dispatch to critical fuel conservation dispatch	Prolong time before more serious emergency actions are necessary
Purchase excess industrial generation	Add generating capacity
Purchase emergency power from other utilities	Often make substantial power available, but at high cost
Reduce standby reserves	Increase generating capacity by 50–100% of the capacity of a large unit
Direct load control (customer load management)	Reduce load
5% voltage reduction	Reduce load by 3%
Appeal to industry	Reduce load by 1–2%
Appeal to public	Reduce load by 1–2%
Interrupt interruptible service	Reduce load
Run generating units at extreme outputs	Increase generating capacity by 1–3%
Reduce spinning reserve to zero	Increase generating capacity by the capacity of a large unit
8% voltage reduction (an additional 3%)	Reduce load by 1%
Shed load (rotating blackouts)	Reduce load by amount necessary to balance with supply

[a] Actions are listed in the approximate order in which they would be implemented.

Although such differences can result in diverse effects on the utility, the possible responses by the utility do not differ in many ways.

For the outages with short duration, or whenever a short-term difficulty in meeting daily loads arises, most utilities have a well-established series of emergency operating procedures that can be implemented. A set of typical procedures is listed in Table 7.I. The order in the table is approximately the order in which the actions would be implemented, with the last-resort actions shown at the bottom. Of course, an outcome worse than rotating blackouts would be a blackout for the entire generating system. The actions listed give a utility a considerable margin to work with before shedding load. However, instituting even the first procedure is in some sense a failure, which the utilities would prefer to avoid. Typical measures of system reliability (Section 7.1), such as LOLP, measure the probability that any of these actions will have to be taken in a particular time period. Accounting for the effects of the emergency procedures that can be implemented before shedding load would reduce the LOLP significantly from the value it has before any of these procedures are implemented.

Other options that can be exercised by a utility facing a short-term outage of a generating unit include temporarily postponing scheduled maintenance on other units, and purchasing power on a short-term basis from other utilities. The types of outages for which such actions are most useful are indicated in Table 7.II. Scheduled maintenance, shown as an outage class, normally does not require actions by the utility because maintenance is planned in advance. Occasionally, a short-term purchase may be needed, or the emergency operating procedures may be implemented.

Also indicated in Table 7.II are actions for outages with longer durations, such as long-term shutdowns, permanent shutdowns and, possibly, deratings of generating units. For these classes of outage, the major actions take some time to implement, for example, changing the construction schedule, arranging long-term purchases, implementing vigorous load management and conservation programmes, or imposing restructured rates that tend to improve the system's load factor. Of course, the actions that are indicated for unscheduled outages and short-term shutdowns could also be used during difficult time periods for long-term or permanent shutdown. However, those actions would generally not be satisfactory long-term responses.

7.3. VALUE OF RELIABILITY

7.3.1. Introduction

Traditionally, the discussion of electric utility system reliability focused only on the technical and engineering standards applied in system expansion planning. Such standards had been established both through utility management policy and long-term engineering practice. More recently, however, the determination of an appropriate level of system reliability has come to include the explicit consideration of both technical and economic criteria, not only from the utility's point of view but from that of the customer as well. An important factor now included in establishing the economic criteria for expansion planning with adequate system reliability is the value the utility's customers place on reliable electric services.

This section introduces and defines the concept of value of electric service reliability to the consumer. To put the problem of measuring the electricity consumer's value function in perspective, the relative importance of monetary and non-monetary costs are discussed within the framework of a customer

TABLE 7.II. MATRIX OF UTILITY OPTIONS FOR VARIOUS TYPES OF OUTAGES OF LARGE GENERATING UNITS

Utility action	Scheduled maintenance	Unscheduled outages	Short and intermediate shutdown	Long-term shutdown	Permanent shutdown	Derating	Delay in commercial operation
Temporarily postpone scheduled maintenance		X	X			X	X
Institute emergency operating procedures	X	X	X			X	X
Short-term purchase	X	X	X			X	X
Long-term purchase				X	X	X	
Implement load management and conservation programmes				X	X	X	
Defer planned retirements		X	X	X	X	X	X
Accelerate existing construction schedule				X	X	X	X
Add new capacity to construction schedule				X	X	X	
Impose restructured rates				X	X	X	
Increase interconnections				X	X	X	

classification scene which has been found useful for the presentation and discussion of customer value functions. Next, some of the important factors that tend to limit the quantification of customer value functions to estimates of incurred economic losses due to service interruptions are discussed. This is followed by a description of three general approaches used to estimate service interruption costs together with a presentation of results derived from the applications of each approach.

7.3.2. Value of reliability: definition and concept

A fundamental component in an optimal level of electric service reliability is the value customers place on reliable electric services. Electric service reliability can be defined as the level of continuity and quality of electrical supply to a utility customer's end-use device [10]. Ideally, value is the total unit price that a consumer would pay for electrical energy at a given level of reliability. Value thus includes an internal or monetary component and an external or non-monetary component. In each individual's valuation of electrical service reliability, that person implicitly assigns some monetary measure to the latter component. In some cases the customer may explicitly assign a monetary value to external costs, as demonstrated, for example, by the purchase of an emergency backup generator specifically to avoid any inconvenience from power interruptions.

Internal and external costs due to an interruption in electrical services will vary extensively from one customer class to another, depending on numerous independent factors. Even two customers within the same class, subjected to identical power interruptions and incurring similar monetary losses, may be exposed to severely different external costs. Moreover, in accordance with the individual customer's tolerance to those costs, each may value more reliable service in differing amounts. For example, energy supply in the food industry may be more important because of possible spoilage; in other industries, the interruption may only result in a postponement of production.

For the discussion of service reliability and customer value functions, it is convenient to classify customers based on their general electricity use characteristics. A reasonable disaggregation might include the following six groups:

Large manufacturers
Small manufacturers
Commercial
Institutional
Agricultural
Residential.

The electricity-use characteristics of large and small manufacturers (collectively referred to as industrial customers) are similar. Industrial customers normally have a relatively large demand (kW) for electric power that remains quite stable from day to day or season to season. In general, larger industrial customers, with continual production activities, have the most uniform demand for electric energy. Smaller customers who may run only two shifts per day with no weekend production have lower demands during evenings and weekends, although they exhibit a fairly constant demand during production hours.

Commercial and institutional demand curves are relatively high but constant during the daylight hours of the normal business day and fall off during the night hours. Evening demand may fall off gradually owing to the accommodation of evening shopping hours in many retail outlets. These classes of customer also show seasonal variations as a result of space conditioning and seasonal differences in lighting, which constitute their major energy requirements.

Residential and farm customers show even greater temporal variability in their demand for electrical power than commercial and institutional customers. Demand, particularly by residential customers, is very strongly dependent on seasonal weather variations and also exhibits very pronounced daily peak demands during the early morning and early evening.

With these customer classifications in mind, the concept of electric service reliability value can be more easily visualized with the aid of Fig.7.4. This figure graphically displays the concept of value in terms of its internal and external cost components. On the base plane of the figure, each of the six customer regimes is defined in terms of an internal/external cost space. Each regime is shown as a range of internal and external costs to emphasize the uncertainties in estimating these costs. Also, the relative positioning, size and shape of these regions may vary significantly according to such factors as geographical area, specific customer mix within each group, season, expected outage characteristics (e.g. frequency and duration), etc.

The vertical dimension in Fig.7.4 represents the value that each customer group might assign to an increment of service reliability and be willing to pay for. Value is also subject to a significant amount of uncertainty and variability as indicated by the irregular upper limit on each bar. The value that each group assigns to electric service reliability is a function of its aggregate tolerance toward both the internal and external costs expected to result from power interruptions that define the cost regimes in the base plane of the diagram.

The value that industry places on electric service reliability can, in general, be expected to be characterized and dominated by high monetary or internal costs and relatively low external costs. Commercial customers may also be characterized by relatively high monetary costs but moderate external costs when faced with an unexpected power interruption. Institutions such as hospitals, police and fire departments or community water departments may experience only minor internal costs but high external costs owing to their roles in maintaining social order and well-being. In the event of a power interruption, agricultural customers may experience relatively high monetary costs depending on the type of farming operation and specific uses of electricity. Finally, the major loss

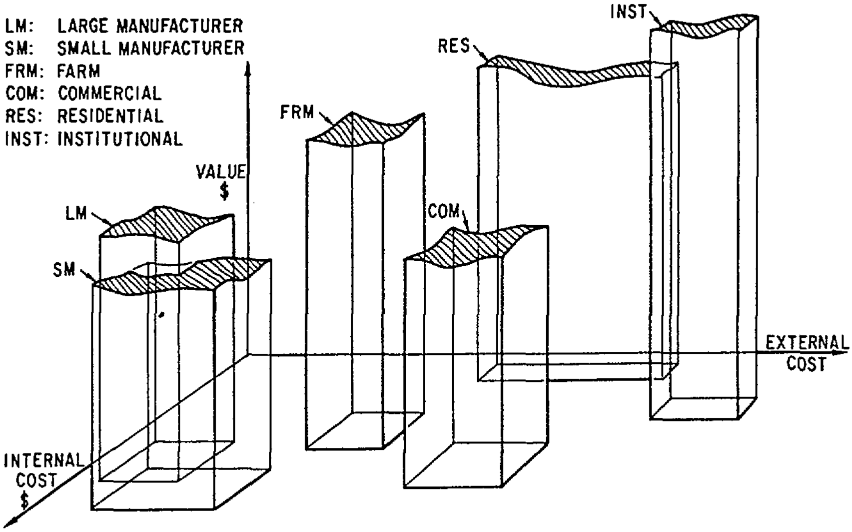


FIG. 7.4. Possible set of customer interruption costs and values of electric service reliability.

incurred by most residential customers is the inconvenience associated with an interruption of electrical service.

7.3.3. Factors limiting accurate determination of value

The understanding of customer value of electric service reliability is important conceptually, but several important factors tend to limit an accurate analytical determination of it; one of these factors is the wide variability of incurred losses resulting from service interruptions even among customers engaged in nearly identical activities.

Another factor is that external non-monetary costs are extremely difficult to quantify, and thus it is even more difficult to assign a value to them. This valuation problem exists not only for the researcher or utility analyst but also for the customer. It is not usually possible for a customer to perceive accurately, or even identify, the external costs associated with a level of service reliability that has not actually been experienced. This was exemplified when two groups of utility customers were asked to rate the seriousness of various durations of power outages. The group of customers who had recently experienced those outages uniformly rated each as less serious than did a group of customers who had not experienced any recent power failures [11].

The extreme complexity and difficulty in quantifying the external, non-monetary, component of value has led most utility planners and researchers to attempt to quantify only the direct, internal or monetary component of electric power interruption costs, while continuing to recognize the existence and importance of external costs in defining an appropriate level of system reliability [12, 13]. Indeed, a customer's value of reliability must be at least as great as the product of expected economic losses caused by a service interruption and the probability of that interruption occurring, summed over all possible interruptions [10].

Correspondingly, numerous estimates have been made of the direct internal costs of electric service interruptions to various customer classes. The major approaches employed to establish these costs include:

- Production factor analysis
- Economic welfare analysis
- Empirical analysis or customer surveys.

The choice of a particular approach reflects most often the availability of data and the analytical preference of the researcher. From an analytical standpoint, it is preferable to select a method that is well supported on both a theoretical and an empirical basis. In practice, only a well-designed and comprehensive customer survey approach has been shown to be both empirically valid and supported by theoretical analysis.

Each of the three methods is described in detail in the subsections below, with a summary of the relative advantages and disadvantages of the approach. Discussion of each approach is concluded with a summary and evaluation of results drawn from studies based on the respective methodology.

7.3.4. **Production factor analysis** [1, 10]

The production factor analysis approach to estimating electric service interruption costs uses a mathematical representation of the expected relationship among inputs, factors of production and outputs. This approach estimates customer interruption costs as a ratio of some economic index (either output or factor of production) to some input which may be affected by a service interruption. This relationship generally takes the form:

$$\text{Service interruption cost} = \frac{\text{Economic index}}{\text{Input}}$$

Typical economic indices used in this approach include value added by manufacturer, gross national or state product and, less often, wages. Input is usually measured by electric energy consumed (kW · h) over the same period as the economic index is measured, but occasionally it is represented by electricity demand (kW) or duration (h). Theoretically, this method assumes that normal development of the selected economic index ceases during a service interruption which can be characterized by unserved energy, demand not met, or duration of failure.

One modification to the production factor approach is to recognize, in addition, damage and clean-up expenses as well as the opportunity cost of capital resources left idle during a service interruption.

The advantage of this approach lies in its simplicity and ability to capture both direct and indirect internal economic impacts. Appropriate data are usually available to estimate service interruption costs within political or census boundaries. Among its shortcomings are determination of long-term average rather than short-term marginal impacts and the use of certain necessary assumptions such as a homogeneous output for each industry. Because of these shortcomings, this method lacks sensitivity to certain outage characteristics and to short-term (less than 24–48 h) service interruptions. It will be shown later that interruption costs estimated by the production factor analysis technique approximate the long-duration service interruption costs developed through customer surveys while underestimating the unit costs of short-duration outages.

Table 7.III summarizes the methods and results of a wide range of customer interruption cost estimates derived through analysis of various production factors. With few exceptions, nearly all the reported studies were published in the period late 1960s to mid-1970s. Any comparison of the quantitative results of service interruption costs presented in these studies must recognize the presence of a number of limiting factors relating to the wide variation among studies in terms of the outage conditions assumed and in terms of the study design and quantitative production factors employed in the analyses. The use of statistical methods to analyse and compare these data is therefore difficult, if not inappropriate, given the presence of these study variations.

Nevertheless, inspection of the production factor analysis results presented in Table 7.III indicates a relatively narrow range which bounds most of the service interruption cost estimates. This range is between $0.50 and $1.50/kW·h, which brackets all or part of nearly two-thirds of the published service interruption cost estimates developed for many countries throughout the world. Estimates or ranges that extend above this band are usually attributable to highly automated, low-demand industries such as those characterized in the USA by Gannon [17]. Thus, the high interruption cost estimates are usually the result of the presence of a low electricity consumption rate in the denominator of the factor analysis equation, rather than a high absolute monetary loss contained in the numerator of the equation.

7.3.5. Economic welfare/consumer surplus analysis

Applied welfare analysis normally strives to quantify consumer gains or losses through the concept of consumer surplus. In its simplest terms, consumer surplus is value minus cost. It measures the difference between what a consumer is willing to pay for a certain amount of one particular product and the price he

TABLE 7.III. SUMMARY OF SERVICE INTERRUPTION COST ESTIMATES BASED ON PRODUCTION FACTOR ANALYSIS METHODOLOGY

Study	Method	Scope	Estimated cost[a]
Telson, 1972 [12]	Wages/non-residential kW·h	New York State	\$1.17/kW·h
Telson, 1975 [14]	Wages/non-residential kW·h	New York State USA	\$1.22/kW·h \$0.57/kW·h
Shipley, 1972 [13]	GNP/kW·h	USA	\$0.60/kW·h
Kaufman, 1975 [15]	Cost of peak kW·h $\times \dfrac{\text{Value added}}{\text{Elec./revenues}}$	New York State	\$0.77/kW·h
Hausgaard, 1971 [16]	Wages/h	New York State	\$2.17 million/h or \$0.45/kW·h
New York State Economic Dvlpmnt Admin., 1971 [15]	Wages/h	Central Manhattan	\$2.5 million/h or \$0.75/kW·h
Gannon/IEEE, 1971 [17]	Not specified	US highly automated low-demand industry US less automated high-demand industry	\$10.00/kW·h \$1.50/kW·h
Environmental Analysts Inc., 1975 [18]	Wages/kW·h	Wisconsin industry and residential	\$1.00/kW·h
Stanford Research Inst. (SRI), 1977 [19]	Wages/kW·h + restart costs	Northwest Power Pool – short term Northwest Power Pool – long term Northwest Power Pool – long outages	\$21 million /h \$14.5 million/h \$1.36/kW·h

National Economic Research Assoc. (NERA), 1976 [20]	GNP/kW·h	USA in 1983	\$0.61–\$1.20/kW·h
Khazzoom/Stanford Univ., 1976 [16]	Gross State product/kW·h	California	\$0.64/kW·h
Federal Power Commission, 1976 [21]	GNP/kW·h	USA	\$0.50/kW·h
Munasinghe, 1977 [22]	Short-run opportunity costs	Small Brazilian region, industry	\$1.00–4.00/kW·h
	Value added/kW·h	Taiwan, industry	\$0.05–1.20/kW·h
	Industrial output/kW·h	Sweden, industry	\$1.00–2.00/kW·h
Jaramillo, Skoknic, 1973 [23]	Value added/kW·h	Chile, industry	\$0.17–2.33/kW·h
Shepard/Electricity Council, London, 1965 [24]	Wages lost	London, industrial London, commercial	\$2.08/kW·h \$3.86/kW·h
Belgium/Société de traction et électricité [24]	GNP/kW·h	All sectors	\$1.50/kW·h
Lundberg, Jomier, 1969 [25]	Value added/kW·h	Sweden, industry Sweden, commercial	\$1.50–4.50/kW·h \$2.00–2.50/kW·h
Lundberg, Jomier, 1961 [25]	GNP/kW·h	France, all sectors	\$1.23/kW·h
Israel Electric Corp. Ltd [24]	Based on US studies	Israel, all sectors	\$0.50/kW·h
New Zealand, 1976 [26]	Half wages/kW·h	Industrial Commercial	\$0.56/kW·h \$0.72/kW·h
Japan, 1979 [24]	GNP/kW·h	All sectors	\$2.34/kW·h

[a] Presented, where possible, in terms of US \$/kW·h in the year the study was reported.

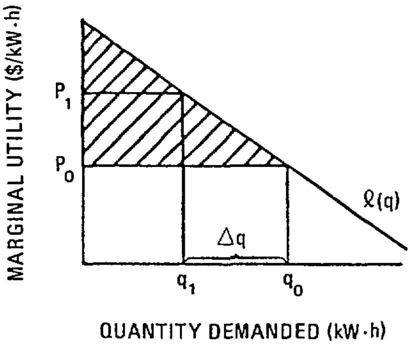


FIG. 7.5. Long-term demand schedule for electrical services.

must actually pay. Consumer surplus measurements are derived from well-known conditions for consumer utility (satisfaction) maximization [27].

A long-run demand schedule, $\ell(q)$, is shown in Fig.7.5. Each point on the demand curve represents the incremental value to the consumer for the last unit of goods purchased. Given a uniform price, P_0, the consumer will purchase q_0 amount of goods. At this equilibrium demand point, the last unit purchased has a marginal value to the consumer that is just equal to the price. Hence, for the final or marginal unit purchased, the consumer derives no benefits for which he does not pay, i.e. he derives no 'surplus' benefits. But for all incremental units of goods preceding q_0, the marginal utilities are shown by the demand curve to be of greater value to the consumer. With the purchase of q_0 units at uniform price P_0, the consumer derives some incremental surplus benefit from each unit preceding q_0. The incremental consumer surplus for unit q_1 is given by the difference between the unit price the customer would be willing to pay at q_1 and the uniform price actually paid at equilibrium consumption of q_0, i.e. $P_1 - P_0$. Total consumer surplus is the integral under the demand curve from zero to q_0 units, less the customer's total cost for the purchase of q_0 units of goods, or

$$\text{Consumer surplus} = \text{total utility} - \text{total costs}$$

$$\text{Consumer surplus} = \int_0^{q_0} [\ell(q) - P_0]\, dq$$

$$\text{Consumer surplus} = \int_0^{q_0} \ell(q)\, dq - P_0 q_0$$

where:

$\ell(q)$ is the long-run demand schedule
q_0 is the equilibrium demand
P_0 is the equilibrium unit price.

Any event in the electric utility supply system, such as an interruption, that prevents the customer from consuming up to the equilibrium quantity of q_0 forces the consumer to forgo some amount of consumer surplus. Thus, the loss in welfare, or consumer surplus forgone, owing to an interruption which restricts the customer to consuming only q_1 kW·h of electrical energy, for example, is given by

$$\text{Consumer surplus} = \int_{\Delta q} \ell(q)\, dq - P_0(\Delta q)$$

The available literature on long-term demand elasticities (percentage change in quantity divided by percentage change in price) indicates a range from −0.224 to −0.150 for the residential sector alone. Application of these values in the above equations for a 'typical' US utility results in a customer interruption cost ranging from \$1.10 to \$9.40/kW·h.

Although a wide range of values can be derived from published demand elasticities, the long-term welfare analysis methodology has the advantage of being based on economic theory and being relatively easy to calculate given the demand elasticity for electric energy. Also, because this method is based on observed market behaviour, it is able to capture both the internal and external factors as well as those associated with a consumer's willingness to pay for electrical service in the long term.

In another approach, a theoretical model of economic welfare is formulated on the basis of the relative value of electricity and other goods. Consumers are assumed to respond to a power interruption by substituting one type of goods for the other to maximize their 'satisfaction' within a fixed income. 'Satisfaction' is defined as the utility function that combines the assumed value of each type of goods into a single measure. Two studies employing this approach were funded by the Electric Power Research Institute [28, 29]. Although Tolley and Wilman [30] have applied this approach in evaluating the effects of oil embargoes and other interruptions in the supply of goods, its applicability to electric service interruptions is limited by the difficulty of obtaining short-run price elasticity data to describe the willingness of consumers to substitute one type of goods for another. In addition, this approach values electricity as an end-use rather than as an intermediate item of goods, thereby making the assignment of value even more indirect and questionable.

Another problem with this approach is that it is based on direct extrapolation of consumer behaviour in a non-interruption situation to their behaviour when faced with an interruption. That is, an observed willingness to pay for planned electricity service is not necessarily an accurate estimate of the willingness to pay to avoid unplanned interruptions in service. The former is best described by the long-run demand curve and associated long-run price elasticities for which a significant amount of data has been compiled. The latter is best described by a short-run demand curve and price elasticities for which few if any good estimates are available. Unless an interruption in service has been fully anticipated by the consumer, this approach can be expected to underestimate the true costs due to the inconvenience and disruption of normal routines caused by an electric service interruption. Hence, these methods are also insensitive to many important outage characteristics.

7.3.6. Empirical analysis: customer surveys

The customer survey approach is most common among the empirical methods that might be used to estimate service interruption costs. Surveys seek to determine service interruption costs in relation to their impacts on a range of production activities. They typically examine both internal and external aspects of service interruptions, including direct and indirect costs incurred, attitudes and emotions experienced, degrees of flexibility and inconvenience, and mitigating measures which were or may be helpful. Surveys are based on either historical or hypothesized outage experiences.

Customer surveys have the advantage of being direct estimates of the costs incurred, unlike the more indirect theoretical approaches previously discussed. Surveys can also be designed for specific areas of concern by requesting the specific data needed to evaluate those concerns. As such, surveys are able to address attributes in many forms (e.g. internal and external factors), thereby allowing them to focus on service area-specific issues which more theoretical approaches cannot do because of their systematic requirements. Unlike the theoretical approaches, surveys may lack the assurance of consistency across respondents, which may allow biases to influence customer responses [1]. Such biases may not be any more severe than those in the theoretical approaches, and they can be both minimized and well understood if adequate time and financial resources are applied to the design, testing, solicitation and evaluation phases of the survey approach. Herein lies perhaps the greatest disadvantage of the empirical survey approach: done properly, direct customer surveys are expensive and time-consuming.

Several direct customer surveys have been undertaken in recent years. A number of the earlier surveys were very limited in scope and sample sizes, in contrast to more recent efforts undertaken in Finland, Sweden and Canada. The remainder of this section presents the results of various direct customer surveys.

Although other recent surveys are reasonably comprehensive, attention is directed toward an examination of the extensive customer survey work concluded in 1980 by Ontario Hydro, a major Canadian utility.

Table 7.IV summarizes the results of several industrial, commercial and agricultural customer interruption cost surveys conducted since the mid-1960s. Where possible, interruption costs are shown for service interruptions of one hour's duration to facilitate comparison between the various surveys. These surveys generally indicate that service interruption costs range from a few to several dollars per kilowatt hour unserved, with the higher costs in the industries that are not electricity intensive. A more detailed analysis of survey work conducted by Ontario Hydro provides additional valuable insight into key customer responses not detailed in Table 7.IV.

7.3.7. **Ontario Hydro customer survey**

Ontario Hydro is a publicly owned utility servicing the Province of Ontario, Canada. It provides retail electrical service directly to large industrial and rural customers, and wholesale service to over 330 municipal utilities. In 1974, the Ontario Energy Board ordered Ontario Hydro to re-evaluate certain aspects of its system reliability standards including an evaluation of alternative levels of reliability from the viewpoint of selected customer classes. Ontario Hydro therefore undertook to survey five major customer groups to quantify their expected costs and other concerns in the event of interruptions of varying durations. These surveys covered the following customer groups:

- Large manufacturers (> 5 MW peak)
- Small manufacturers (< 5 MW peak)
- Commercial and institutional (general rate class other than manufacturers)
- Residential
- Farms.

The next subsections present the results of Ontario Hydro's comprehensive surveys, which were completed in 1979. Section 7.4 discusses how these results were used in the system re-evaluation.

7.3.7.1. Large manufacturers [38, 39]

In general, the goal of Ontario Hydro's activities was to provide up-to-date and local data on the proper amount of the generation or distribution system reserves. Specifically, the large manufacturers survey was designed to:

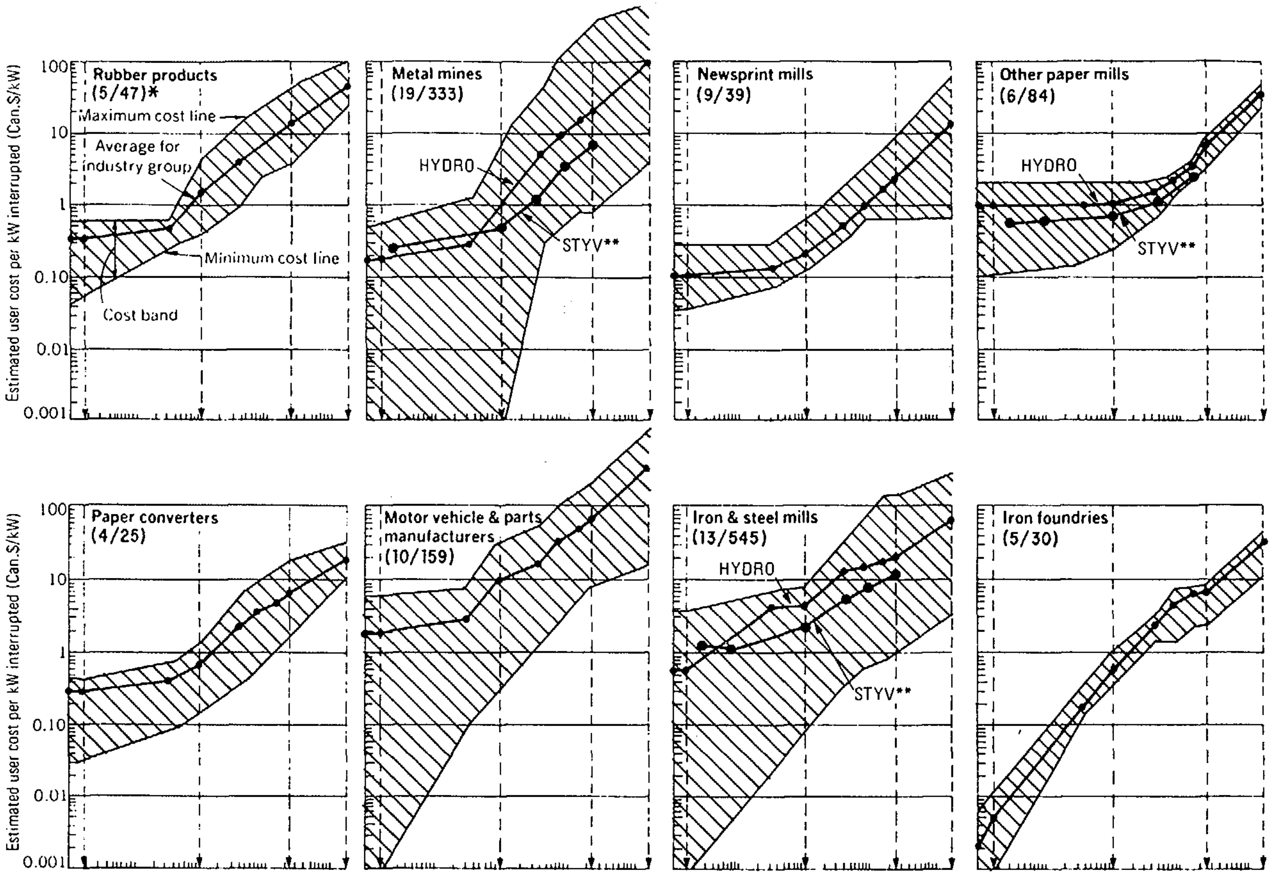
(a) Obtain customer estimates of costs and other effects of electrical energy supply interruptions, voltage variations, frequency variations, and energy rationing;

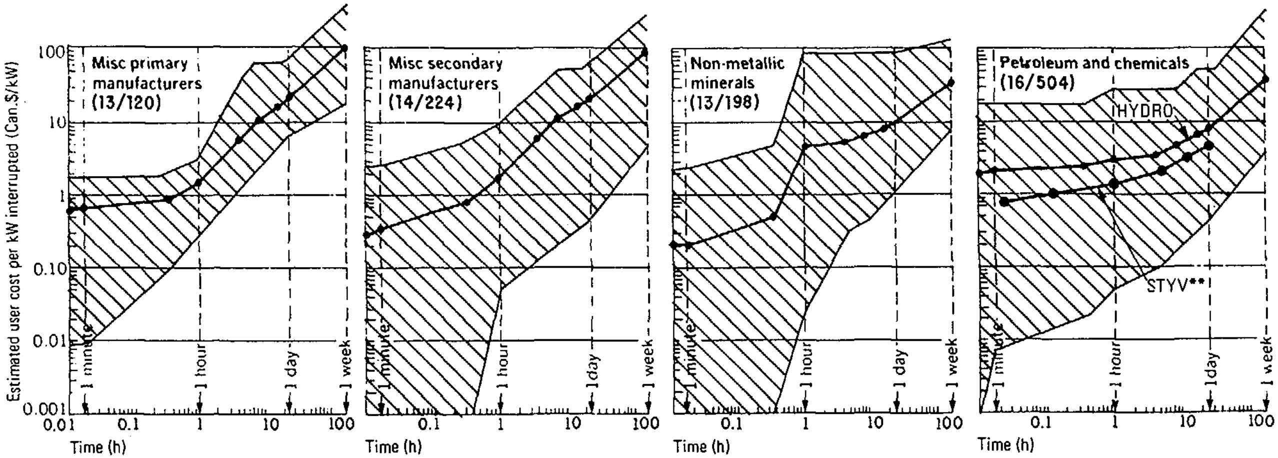
TABLE 7.IV. SUMMARY OF SERVICE INTERRUPTION COST SURVEYS

Study	Outage duration	Scope	Interruption costs (US $/kW·h)		Comments
UK, Jackson, Salvage, 1970 [31]	< 1 min	Industry	0–7.40		Survey of 12 industrial firms
Finland, STYV, 1979–1980 [24]	1 h	Heavy industry			Survey technique and customer classes modelled after that of Ontario Hydro
		– elec. intensive	0.65		
		– non-intensive	2.37		
		Small industry	4.95		
		Services	6.24		
		Institutions	6.02		
		Agricultural	4.52		
		Telecommunications	6.67		
		Transport	7.74		
Norway, Heising [13]	1 h	Industry (excluding petroleum refining)	1.15		
Sweden, Mattsson, 1966 [32]	1 h	All industry	1.12		
Sweden, Munasinghe, 1969 [22]	1/3 h, 1½ h	All industry	0.75[a]	0.74[b]	Survey of 70 firms representing 28% of total industrial electric consumption
		Mines	0.81	0.54	
		Smelting	0.05	0.10	
		Iron and steel	0.34	0.41	
		Workshops	2.26	3.03	
		Quarrying	0.17	1.31	
		Timber	0.38	0.45	
		Pulp and paper	0.41	0.22	
		Graphics	1.96	6.03	
		Food	0.63	0.63	
		Textiles	3.49	1.98	
		Rubber	2.96	1.00	
		Chemicals	0.53	0.29	

Sweden, Lundberg, Jomier, 1973 [25]	1 h	Agriculture	2.48	
		Commercial shops		
		Medium	1.45	
		Large	1.86	
		Offices	0.04	
		Parts	2.07	
		Transport	1.28	
		Urban	1.98	
		Rural	1.65	
USA, Modern Manufacturing, 1969 [33]	1 h	Industry	0.95	
USA, Gannon, 1974 [34]	1 h	Commercial		
		All	7.21	
		Offices	8.86	
USA, IEEE, 1973-1974 [35]	1 h	California, maximum industrial	4.57	
		California, median industrial	1.52	
USA, Congressional Research Service, 1977 [36]	1 h	New York City, all sectors	3.32	
USA, Systems Control Inc. [37]	1 h	New York City, all sectors	3.70	
Canada, Ontario Hydro, 1976–1979 [38]	1 h	Large users	3.97	Adjusted to constant 1980 basis
		Small industrial users	6.31	
		Residential	0.04	
		Large farms	275.70	
		Retailing	7.32	
		Office buildings	14.33	
		Institutions	1.01	

[a] Values for 1/3 h interruption.
[b] Values for $1\frac{1}{2}$ h interruption.


Estimated user cost per kW interrupted (Can.$/kW)
100
10
1
0.10
0.01
0.001
Rubber products
(5/47)*
Maximum cost line
Average for industry group
Minimum cost line
Cost band
Metal mines
(19/333)
HYDRO
STYV**
Newsprint mills
(9/39)
Other paper mills
(6/84)
HYDRO
STYV**
Paper converters
(4/25)
Motor vehicle & parts manufacturers
(10/159)
Iron & steel mills
(13/545)
HYDRO
STYV**
Iron foundries
(5/30)



*NUMBER OF RESPONDENTS/SUM OF PEAK MWs
**RESULTS OF SIMILAR SURVEY CONDUCTED BY FINNISH POWER PRODUCERS' COORDINATING COUNCIL (STYV)

FIG. 7.6. Ontario Hydro Survey user-estimated service interruption costs by major industry group: 1976 Canadian $/peak kW versus duration of interruption (from [41]*).*

(b) Gather data on industry groups for use in planning and operating the system;
(c) Obtain information for use in seeking consumer co-operation to reduce adverse effects of operating problems that might occur in the future.

This survey was initiated by a letter to all customers in the large user group. Ontario Hydro staff then visited each member of the group to deliver and discuss the questionnaire which was left with the customer for completion. Follow-up visits were made to expedite response. Customers with a total of 199 contracts were asked to complete questionnaires. There were 172 responses, which are considered representative of large users in terms of geographical distribution and type of industry. Ontario Hydro identified 24 industry groups but, in order to maintain confidentiality, the respondents were combined into 12 industry groups when reporting cost of interruptions.

The sum of the respondents' peak demands in 1975 was 3900 MW; their energy use in that year totalled 17 500 GW·h. This energy use is 87% of the total electricity consumption for all 199 potential respondents and about 25% of Ontario Hydro's electrical generation in 1975.

Among a series of other questions, respondents were asked to estimate the costs of interruptions for nine specified durations (< 1 min, 1 min, 20 min; 1 h, 4 h, 8 h, 16 h; 1 day; 1 week). In the questionnaire, cost of interruption was defined to include:

– Cost because of loss of production;
– Out-of-pocket expenses such as labour, materials (spoilage), overhead, clean-up, etc.;
– Damage to production equipment, if any.

Reported cost estimates covered only the costs incurred by the user. They do not include any costs to the community such as unpaid wages, or cost incurred by others because of delays in delivery. Respondents indicated confidence in their estimates ranging from 30% to 100%, the average being 74%.

Figure 7.6 presents the cost estimates for individual industry groups. Because the respondents varied widely in size, individual cost estimates would not indicate the relative sensitivity of each group (or respondent) to an interruption. The cost estimates for each group were therefore divided by the sum of the peak demands of the respondents in the group, producing an estimate of cost in $/kW of peak load. For the industrial group, peak kilowatts is also a reasonable estimate of average demand because large industrial users' demand curves are relatively flat.

It is interesting to note the wide variations of minimum and maximum costs about the average cost lines in Fig.7.6. In nearly every case, the range of cost estimates varies at least an order of magnitude above and below the average over a large range of outage duration.

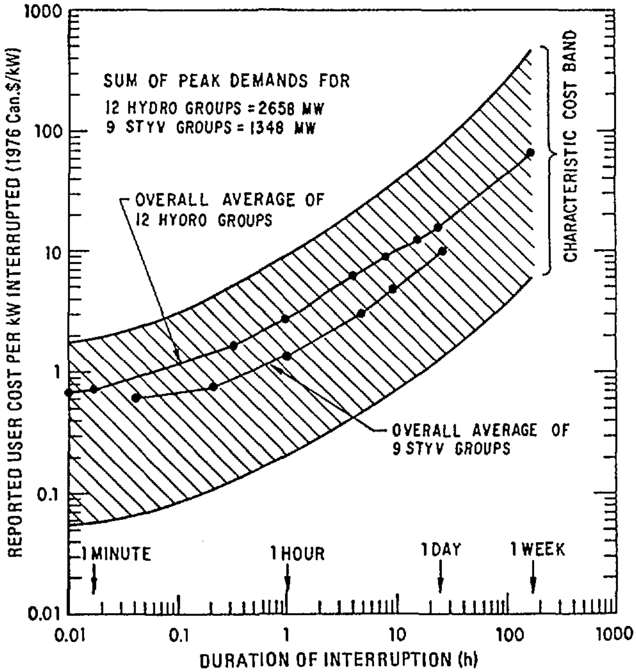


FIG. 7.7. User-estimated service interruption costs for large manufacturers (Ontario Hydro Survey).

Figure 7.7 shows the band of average user-estimated cost of interruptions versus outage duration. Also shown is the overall average cost as a function of outage duration based on the 12 industry groups defined by Ontario Hydro. The wide variation in average costs corresponds to the wide variation of industry groups represented, yet it is encouraging to note that the industry group's average cost curves display a well-defined characteristic band. It is even more encouraging to compare the overall average of Ontario Hydro's 12 industry groups with the overall average exhibited by the Finnish Power Producers Co-ordinating Council's (STYV) nine industry groups based on a 1979–80 survey conducted in Finland. The STYV survey was modelled after Ontario Hydro's survey so that the results are directly comparable [40]. This is particularly interesting in view of the wide range of individual responses received from each industry group. In four cases, the STYV industry groups were defined similarly to those of Ontario Hydro. These include metal mines, paper mills, iron and steel mills and the petroleum and chemicals classification. The average group response of these STYV groups is compared with those of Ontario Hydro in Fig.7.6. Again, a remarkable similarity exists, even within groups where individual respondents varied widely.

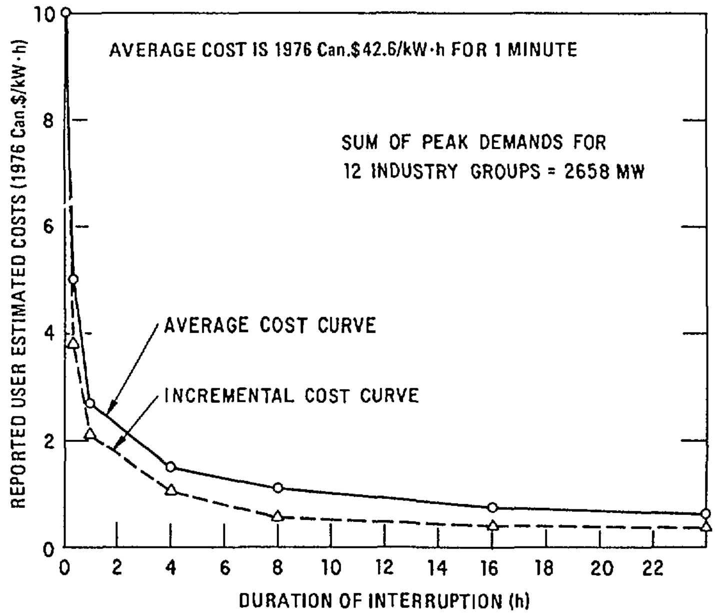


FIG. 7.8. Rate of change of interruption costs for large manufacturers (Ontario Hydro Survey).

Figure 7.8 shows a plot of the rate of change of overall average large manufacturers' losses as a function of outage duration. As the figure indicates, the function is a strongly decreasing one for outage durations less than 4–8 h. Also, an asymptotic value of approximately Can. $0.50–0.60/kW·h is approached as outage durations increase to greater than 20 h. This value is within the range of customer outage cost functions based on the production factor analysis approach. This is not unreasonable, since each represents costs incurred owing to long-term power interruptions.

Ontario Hydro's survey of large manufacturers goes much further than quantifying customer losses. For example, the respondents were asked to indicate, over ranges of outage duration, the relative importance of inconvenience, hazard and dollar costs. Responses indicate that dollar cost, regardless of duration of interruption, is the most important factor, and that it became progressively more important with the duration of the interruption. Inconvenience was second when the duration was one minute or less; hazard took second place when the interruption lasted 20 minutes or more.

Another interesting survey result is the effect of voltage variations on customer production. Normally, utilities reduce voltages in steps: first 5%, then 8%. A 5% voltage reduction would curtail the production activities of about 17% of the respondents, and an 8% reduction would curtail production activities of about 38%. The extent of the curtailments is not specified, nor was this information requested in the survey.

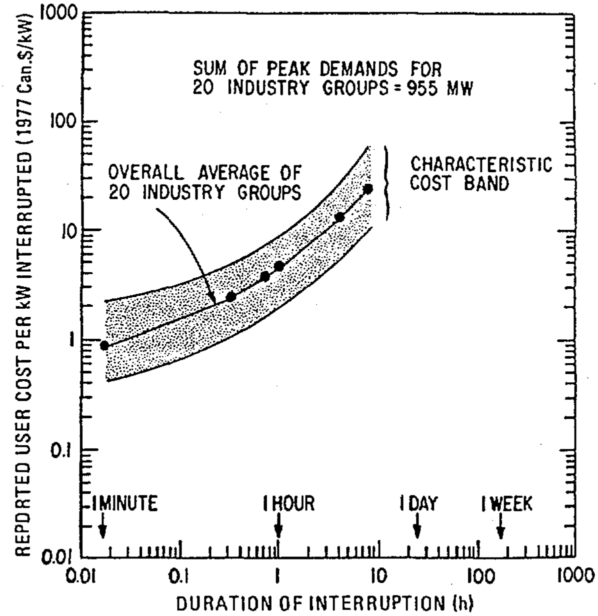


FIG.7.9. User-estimated service interruption costs for small manufacturers (Ontario Hydro Survey).

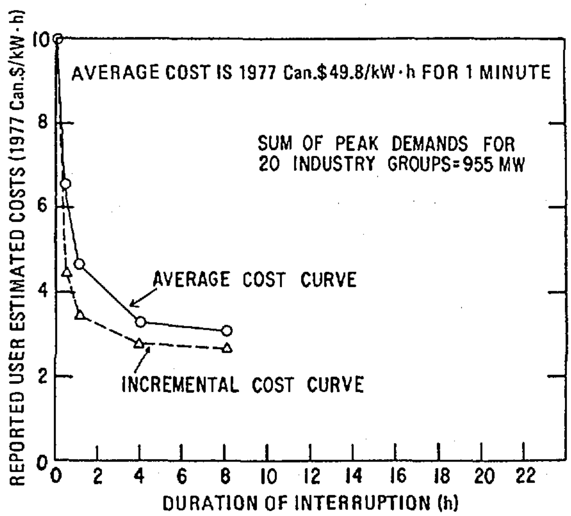


FIG.7.10. Rate of change of interruption costs for small manufacturers (Ontario Hydro Survey).

Industrial customers responded to additional questions too numerous to mention here. Some of these were concerned with the number of employees that would be laid off in various interruptions; others were concerned with interruptible loads and the customer's ability to segregate loads; still others sampled the customer's attitude toward electric power rationing and conservation, and the amount of standby capacity available for emergency generation. Customer responses to some of these questions are summarized in Section 7.3.7.6 below.

7.3.7.2. Small manufacturers [38, 42]

Ontario Hydro's survey of small manufacturers, less than 5 MW peak demand, took a similar form to that of the large manufacturers. Follow-up visits were not conducted with small manufacturers, and results are based on 3574 responses to 14 000 establishments surveyed. Figure 7.9 shows the band of average responses from each of 20 industry groups as well as the overall average. In general, the interruption costs reported by small manufacturers were somewhat higher than those for large manufacturers but spanned a much narrower range.

As shown in Fig.7.10, small manufacturers' costs also showed a strong dependence on outage duration. The average cost for the respondents was almost \$50/kW·h for a one-minute interruption, which is comparable to the \$43/kW·h exhibited by the large manufacturers. The small manufacturers' cost as a function of outage duration, however, tends to fall off somewhat more slowly, approaching an asymptotic value of about \$2.00/kW·h. This value is higher than that approached by the large manufacturers but is not inconsistent with the upper range of long-term interruption costs derived through production factor analysis.

Small manufacturers were also asked to respond to a series of questions related to other aspects of system reliability. For example, the survey revealed that most of the respondents could tolerate a 5% voltage reduction without curtailing production. A 10% voltage reduction, however, would cause production curtailments for most respondents. Nearly 80% of the respondents reported that emergency interruptions would cause serious hazard to humans or to the environment. This is in contrast to the large manufacturers, who placed direct economic losses highest on their list of concerns and placed hazards second when interruptions lasted 20 minutes or more.

7.3.7.3. Commercial and institutional customers [38, 43, 44]

Commercial and institutional customers were surveyed in three separate groups: retail trades and services; office building owners and tenants; and government agencies and institutions.

Interruption cost estimates for the retail trades and services group are based on a sample of 669 retailers contacted by Ontario Hydro. The average monetary

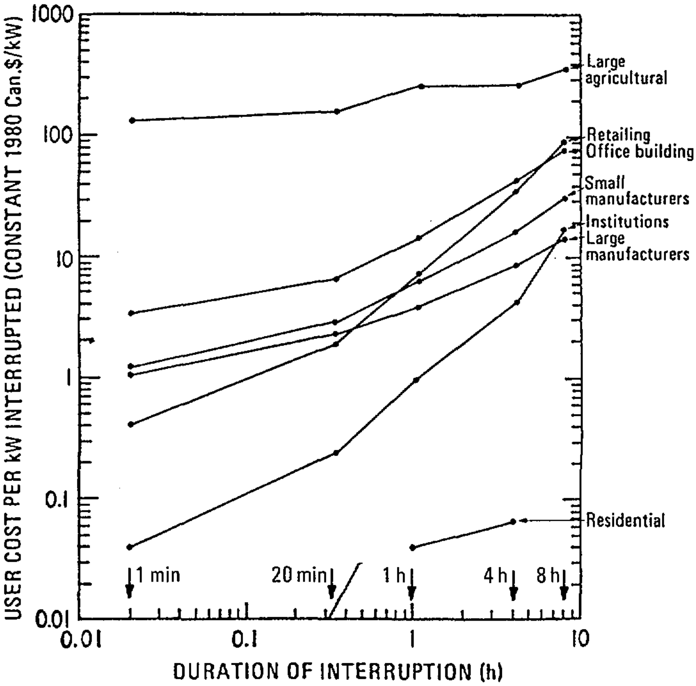


FIG. 7.11. User-estimated cost of electrical power interruptions by customer segment (Ontario Hydro Survey).

TABLE 7.V. ONTARIO HYDRO POWER SYSTEM RELIABILITY SURVEYS: ADJUSTED DIRECT DOLLAR INTERRUPTION COSTS (1980 Can. $/kW)

Duration of interruption	Large users	Small industrial users	Residential	Large farms	Retailing	Office buildings	Institutions
1 min	1.03	1.15	–	122.00	0.39	3.25	0.03
20 min	2.46	3.08	–	174.70	1.93	6.72	0.25
1 h	3.97	6.31	0.04	275.70	7.32	14.33	1.01
4 h	9.02	17.48	0.07	275.70	37.35	46.83	4.44
8 h	13.26	32.26	–	351.90	98.21	81.16	17.63

cost of electric power interruptions tended to be highest for food services and lowest for retail trades. For electric power interruptions exceeding four hours, retail trade and service customers reported costs higher than any other classification except large agricultural users.

Office building owners and tenants also reported interruption costs significantly higher than all other classifications except large agricultural users for outages of less than four hours' duration. For outages from four to eight hours, building owners and tenants reported costs similar to those of the retail trades group. These results are based on a survey of 81 office buildings and 481 tenant organizations.

Ontario Hydro's survey of government agencies and institutions consisted of a sample of 317 respondents. Direct monetary costs estimated by this group were significantly lower than all other groups except residential customers for outages of less than four hours' duration. For outages above four hours, direct costs for this group approach those of the large manufacturers.

Direct monetary cost estimates provided by these groups for interruptions ranging from one minute to eight hours are compared with those of other groups in Fig.7.11 and Table 7.V. As Ontario Hydro surveyed customers over a period of several years, data presented in this figure and table have been adjusted to a constant 1980 dollar (Canadian) basis.

7.3.7.4. Large agricultural users [38]

Based on nearly 4000 cost estimates provided in over 8000 responses from this classification, farm customers display the highest overall interruption costs compared with all other groups surveyed. Cost estimates provided by those customers totalled Can. $235 900 for a one-minute interruption and Can. $6 910 000 for a one-hour interruption. Costs continued to increase with the duration of the interruption. Costs resulting from service interruptions range from Can. $122/kW for a one-minute interruption to nearly Can. $352/kW for an eight-hour interruption. These costs are significantly higher than most other groups because of the relatively high value of the livestock at risk and the relatively low demand profile of most agricultural users.

7.3.7.5. Residential customers [38]

Results for the residential sector are based on responses to surveys of 1239 households. Respondents were asked to place premiums on their electricity rates depending on their perceived need or desire for an 'assured' power supply system. These premiums were later interpreted and quantified.

A hypothetical question was placed before each respondent offering an alternative electric energy supply from an assured system without any interruptions. Respondents were asked how much more they are willing to pay for such a system, given interruption durations of their existing system of one hour and four hours per day. The answers given were in percentages of existing householders' bills, providing a relative but not an absolute answer. The value derived from these initial responses was very low. Accordingly, the survey was repeated with clarification sought for the customer's actual monetary value of the reliability of the system. As shown in Fig.7.11 and Table 7.V, the resultant value was Can.\$0.04–0.07/kW to avoid a 1–4 h power interruption. In contrast, residential customers were paying approximately \$0.02/kW·h for electrical energy at the time of the survey.

7.3.7.6. Other significant results of the survey

Ontario Hydro's customer surveys were designed to solicit information not only on electrical interruption costs, but also on numerous other questions considered important for future expansion planning. Questions ranged from topics such as potential cost savings if adequate advance warning is given of a pending service interruption to preferences for planned interruptions or rationing and hazards associated with service interruptions. A brief review of the principal findings on these and other such topics is presented in Table 7.VI.

7.4. APPLICATIONS OF SERVICE INTERRUPTION COSTS IN UTILITY SYSTEM PLANNING STUDIES

In recent years the concept of service interruption costs to the customer has been incorporated in some studies to determine appropriate levels of electric service reliability. One study, conducted by Ontario Hydro, directly incorporated much of the data just discussed in a comprehensive reassessment of their system expansion programme. Another study by the Electric Power Research Institute (EPRI) applied this concept to an evaluation of the costs and benefits of over or under capacity in four utilities in the USA. A third approach for including reliability in planning is that used by Electricité de France.

7.4.1. Ontario Hydro's System Expansion Program Reassessment Study [43, 45, 46]

The purpose of Ontario Hydro's System Expansion Program Reassessment Study was to estimate the socio-economic effects on Ontario Province of various hypothetical generation expansion programs during the period 1978 to 1997 and to illustrate, among numerous other topics, the relationship between planning reserve margin, system reliability and customer costs. The study's findings in these areas have resulted in a downward shift in Ontario Hydro's long-range planning standard for generation reliability.

TABLE 7.VI. PRINCIPAL FINDINGS FROM RESPONDENTS TO ONTARIO HYDRO SURVEYS ON POWER SYSTEM RELIABILITY

Topics	Large users	Small industrial users	Residential	Large farms	Retail trade	Offices	Institutions
Stand-by electrical equipment	60% had stand-by electrical generation (back-up for 4% of their peak load)	5% had some equipment	Not reported	26% owned stand-by equipment	7% had some equipment	77% of owners and 76% of tenants had some equipment	54% had some equipment (back-up for 25% peak load)
Hazards of interruptions	34% stated that serious hazards exist for humans when an emergency interruption exceeds 1 h; 16% reported serious hazard to the environment for a similar interruption	22% stated that hazards would be created	Not reported	71% stated that hazards would exist to humans, livestock and crops	30% stated that hazards might exist	55% of owners and 17% of tenants stated that hazards might exist	45% stated that hazards might be created
Interruptible loads	49% had facilities to segregate portions of their load	62% had facilities to separate a portion of their load in an emergency	Not reported	60% have facilities to separate load in an emergency	Not reported	Not reported	Not reported
Voltage variation	32% had some voltage regulating equipment; 87% of all respondents reported that they could tolerate a voltage variation of at least 5%	13% had some voltage regulating equipment	Not reported	Not reported	Not reported	Not reported	Not reported

Rationing preferences in *planned* interruptions	69% preferred less frequent but longer interruptions	70% preferred less frequent but longer interruptions	78% preferred more frequent but shorter interruptions	68% preferred more frequent but shorter interruptions	Respondents were slightly more in favour of more frequent but shorter interruptions	Owners opted evenly between more frequent but shorter and less frequent but longer interruptions; tenants were slightly in favour of more frequent but shorter interruptions	Respondents were slightly more in favour of shorter but more frequent interruptions
Adequate advance warnings of outages[a]	27% reported that costs would be reduced			60% reported that costs would be substantially reduced	47% reported ability to make cost-saving arrangements	41% of owners and 44% of tenants reported cost saving possible	30% of respondents stated that costs could be reduced
Given estimate of duration of outage at outset[a]	Not asked			Not asked	39% reported ability to make cost-saving arrangements	40% of owners and 36% of tenants could make cost-saving arrangements	21% of respondents stated that cost-saving arrangements could be made
Length of warning required to reduce costs in hours[a]	Average by industry ranged from 0.2 to 19.5 h			Average 18 h to reduce economic cost	Average of 16 h	Owners required at least 4 h and tenants an average of 20 h	Responses too few to tabulate

TABLE 7.VI. (cont.)

Topics	Large users	Small industrial users	Residential	Large farms	Retail trade	Offices		Institutions
Most costly time for an interruption[a]:						*Owners*	*Tenants*	
Season/month	Winter			May–Sep.	Dec.	Winter	Any month	Winter
Time of week	Weekday			Not asked	Fri.	Weekend	Any weekday	Any day
Time of day	Day shift			Early evening	Mid-morning	Any time	Daylight hours	Daylight hours
Least costly time for an interruption[a]:								
Season/month	Summer			Not tabulated	July	Summer	Summer	Summer
Time of week	Weekend			Not tabulated	Sun.	Any day	Weekend	Any day
Time of day	Night shift			Not tabulated	Overnight	Any time	Night	Night

[a] These topics not discussed with small industrial users or residential respondents.

Ontario Hydro's study has shown that the risk of having insufficient generating capacity to fully supply the load is very small with the 30% target reserve margin called for by Ontario Hydro's traditional reliability criterion – a loss of load probability (LOLP) of 1/2400.[5] It has also shown that risks increase dramatically if the target generation reserve is significantly lower and that uncertainty about the future load forecast is an important factor in the selection of an appropriate level of service reliability. For example, Ontario Hydro calculated that if the planning target for generation reserves was 18% rather than 30%, they could expect 14 incidents each year in which customers would be subjected to rotating load cuts. Such cuts would be made only after managed loads and other interruptible customer loads had been disconnected, voltage reduced by 5%, and appeals made to all customers for voluntary cutbacks.

A further analysis of the numerous factors that gave rise to the expected value of 14 incidents indicated that load forecasting error had the greatest potential for affecting future system reliability at a chosen planning reserve margin. This analysis showed that Ontario Hydro's load forecast errors are approximately normally distributed, with a variance large enough to drive actual generation reserves about 15 percentage points below the planned reserve once every ten years. In this worst-case situation, Ontario Hydro would have less than 3% generation reserves, would be making public appeals for voluntary load cuts every working day, and would be forced into rotating load cuts up to 190 times through the year. In such a worst-case year, a typical customer could expect to have 95 one-hour blackouts.

As part of the reassessment study, Ontario Hydro also made estimates of the costs of unreliability for customers and for the provincial economy. Results of the customer service interruption cost surveys were combined with forecasts of interruptions caused by the generation system over a range of target reserve margins while holding constant the reliability and outage estimates from the transmission and distribution systems. At the time Ontario Hydro conducted the system expansion reassessment, the results of only three surveys were available: large users, small manufacturers and residential customers. Assumptions were made on the outage costs of other customer classifications, but these are judged to have introduced very little error since the groups for which survey results were available consume nearly 80% of Ontario Hydro's electrical energy.

To estimate the expected costs of power outages for the various generation reserve planning targets, Ontario Hydro calculated how often rotating blackouts would be necessary and how severe the generation shortage would be on average. It was then assumed that the load cuts would be borne by all types of customers without distinction and would be applied to each customer for no more than one

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[5] This reliability criterion is considered to be equivalent to an LOLP of one day per ten years, based on only working days, and reflects the risk that the generation system will be unable to fully supply the peak demand for electricity each working day, i.e. 240 days per year.

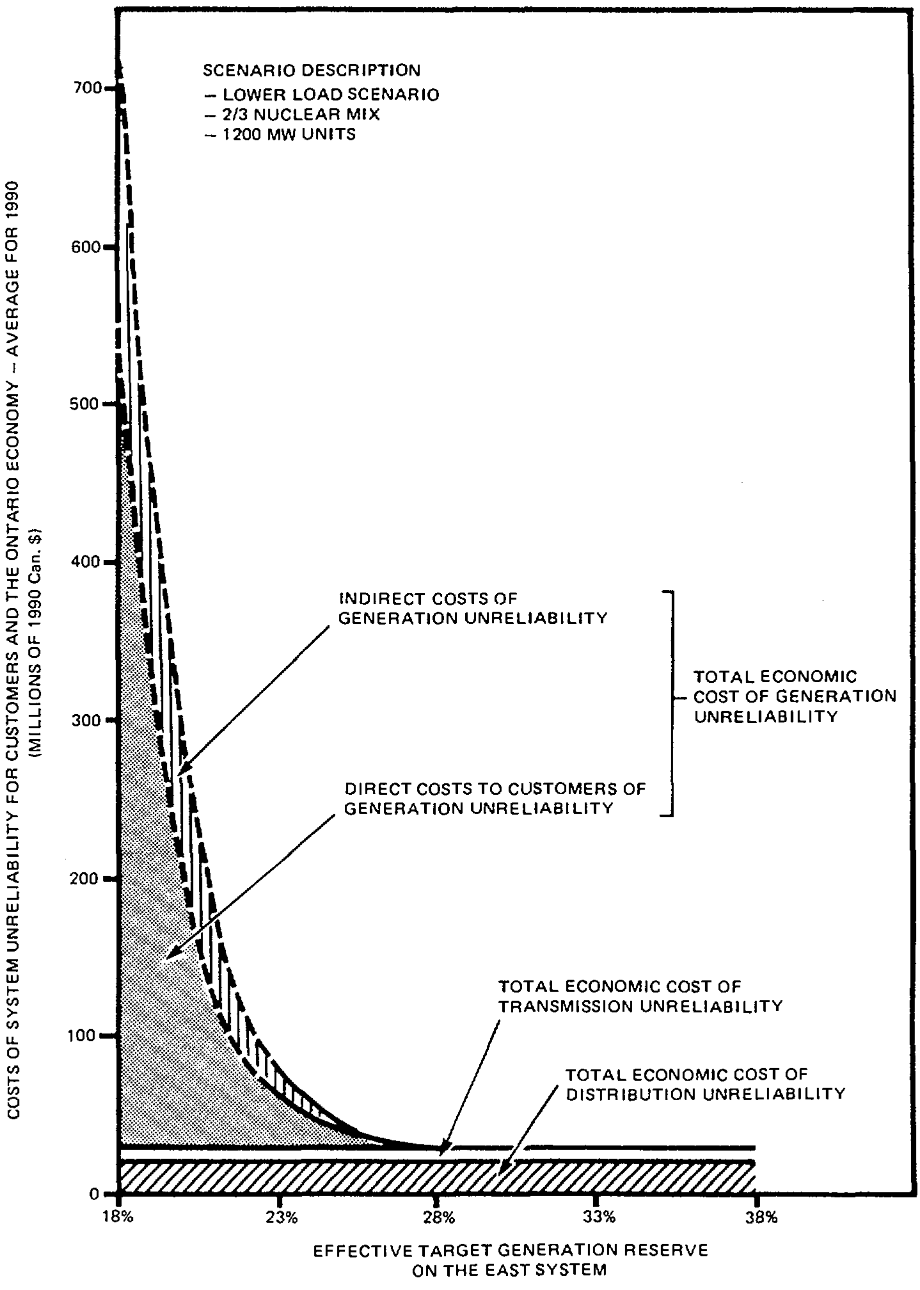


FIG. 7.12. Costs of electric supply system interruptions in 1990 (Ontario Hydro Survey).

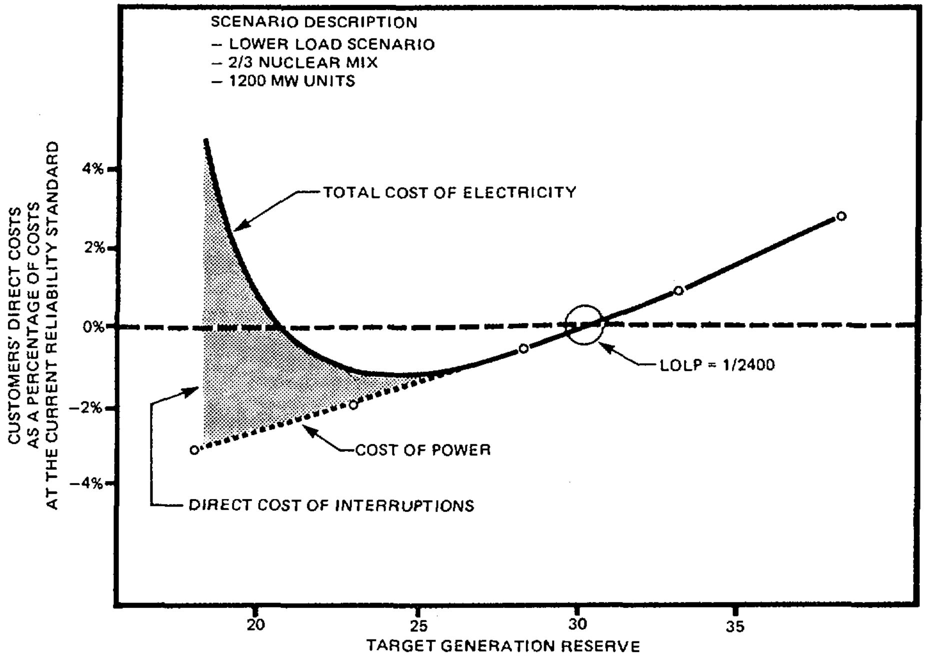


FIG. 7.13. Variation in customers' direct costs with changes in target generation reserve (Ontario Hydro Survey).

hour at a time. On this basis the expected customer losses from power outages were calculated.

To calculate the impacts on the Ontario economy, it was assumed that the direct losses to the industrial and commercial customers would reduce their profits and investment expenditures, and thereby reduce employment and ultimately lower the gross provincial product (GPP). These reductions in the GPP, plus the direct cost in the residential sector, were then used as a measure of the total economic costs to Ontario from generation unreliability. Figure 7.12 illustrates the results of these calculations for 1990, and shows the rather dramatic economic penalties of having insufficient generation reserves.

Another approach was used to evaluate the trade-offs between having too much and too little reserve generation. This approach, illustrated in Fig. 7.13, was to estimate the costs that customers faced directly as a function of target generation reserve. Direct costs include the discounted sum of the cost of electricity and the direct costs of interruptions. As shown in the figure, the analysis indicated that these costs are relatively insensitive to a fairly wide change in target reserve margin and that the minimum cost would appear to result from an expansion programme with a target generation reserve about five percentage points below the level dictated by Ontario Hydro's traditional LOLP criterion. The accuracy of this result must be viewed with some qualifications, however, because the data used for the analysis are not known precisely (as previously shown) and because the techniques used embodied numerous simplifying assumptions, thus ignoring a number of potentially important factors. Nevertheless, Ontario Hydro concluded that a more realistic lowest-cost reliability target should lie somewhere between three and seven percentage points below the level dictated by the traditional LOLP criterion, i.e. between 23% and 27% generation reserve. The relationship between LOLP and reserve margin depends strongly on the assumptions made with respect to future loads and supply options, such as those listed under 'Scenario description' in Fig.7.13.

Ontario Hydro's System Expansion Program Reassessment Study, which directly incorporated consideration of expected customer outage costs, had two significant effects on Ontario Hydro's system planning practices. First, the utility has lowered its generation reserve planning standard to the extent that the planning target for generation system reliability is equivalent to a planning reserve of 25%. Second, a new index of generation system reliability has been adopted. This new index is defined in terms of the expected magnitude of power outages after emergency assistance has been obtained from neighbouring utilities, after managed and contractually interruptible loads have been cut and voltage has been reduced by 5%. The new index is the ratio of unsupplied energy (excluding the emergency cuts listed above) to the forecast peak demand; it has been set at a value of 10 system-minutes (kW-minutes/kW) as the criterion for planning generation system reliability.

7.4.2. Electric Power Research Institute: Costs and Benefits of Over/Under Capacity in Electric Power System Planning [47]

The objective of this Electric Power Research Institute (EPRI) project was to develop a framework for assessing the costs and benefits associated with over or under capacity planning, taking into account the implications of uncertainty in projecting future electricity demand. The project was designed to develop and analyse a model for utility decision-making that dealt with system expansion questions from the utility customer's point of view. The question posed was what planning decisions and schedule would result in the least cost for electric service to the customer, explicitly accounting for service interruption costs and demand growth uncertainty. The subsequent methodology was applied to four separate US utilities which represented a wide range of system sizes, technology mixes, growth characteristics and geographic locations. Although the implication of the EPRI study on each utility is specific to the utility's characteristics, the general conclusions of the study are consistent with those of the Ontario Hydro System Expansion Program Reassessment Study. The methodology and results are discussed in the next paragraphs.

The EPRI methodology integrates utility expansion models with methods for assessing demand uncertainty and customer costs into an overall model for evaluating the probabilistic outcome of over or under capacity planning. The methodology is designed to evaluate the impacts of a chronic mismatch between electricity supply and demand rather than the impacts of a single, widespread demand. Demand in any future year is represented as a range of possible values, each with an associated probability of occurrence. Based on the distribution of possible demand growth scenarios, a capacity expansion decision model schedules capacity additions in three sequential stages: (a) initial planning and studies, (b) licensing, and (c) construction and startup. New plants are committed and move through each of these stages consecutively. However, commitments are made to each stage only when justified by the expected need for power as estimated in each successive year.

In each year, the model plans new capacity for each future year, based on a user-specified planning reserve margin, expected demand, current capacity, and the status of units undergoing initial studies, licensing or construction. The type of capacity chosen is based on the desired long-term mix of fuels. If demand does not develop over time as expected in any specific year, these capacity expansion plans are adjusted in successive years. If actual demand growth turns out to be consistently lower than expected throughout the planning period, the model's initial commitments to capacity additions will tend to overbuild the system and result in an outcome reserve margin higher than the planned reserve margin. When actual demand growth is consistently higher than expected, insufficient long lead time capacity is planned and higher cost short lead time plants must be installed to make up the deficiency. System fixed costs are determined for the resulting expansion plan.

Given peak demand, load shape and installed plants of each technology type for each year, the model uses a probabilistic simulation to find the expected energy generated by each plant for that year. Once the energy generated by each plant is known, the system variable costs are computed. Variable costs as defined here consist of production costs and costs of emergency actions such as purchasing electricity from inter-ties, reducing voltage, and issuing public appeals. These emergency actions are undertaken whenever system capacity is insufficient to meet customer demands. The cost of each emergency action is computed as the expected energy it serves multiplied by the associated emergency charge rate.

When system capacity and emergency actions are insufficient to meet customer demands, energy needs are unserved as brownouts and blackouts occur. The cost of personal hardship and economic losses is determined by multiplying the amount of unserved energy by an outage charge rate in \$/kW·h unserved. This outage rate depends on the value that customers in a particular service area assign to the reliability of electric service. The outage charge rate measures the amount of money that customers, on the average, would be willing to pay to reduce outage energy by 1 kW·h. The outage charge rate as used and interpreted in this study

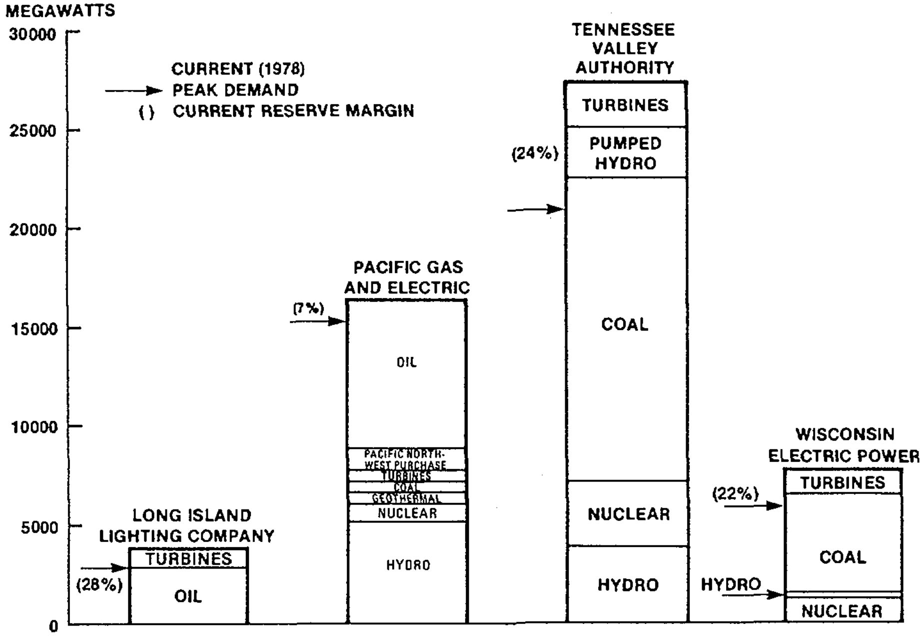


FIG.7.14. System composition of participating utilities (EPRI Study).

thus reflects both direct and indirect costs as a result of unanticipated power outages. EPRI limited its assessment of outage costs to the use of published values from many of the existing studies previously reviewed in this guidebook and assessments developed by the participating utilities. A sensitivity analysis was then used to determine how important the outage charge rate is in influencing the least-cost planning reserve margin.

This study was conducted jointly with four participating utilities in the USA: Long Island Lighting Company (LILCO), Pacific Gas and Electric (PG&E), Tennessee Valley Authority (TVA), and Wisconsin Electric Power Co. (WEPCO). These utilities represent a wide range of system and expansion characteristics as indicated by the system composition, peak demand and reserve margin for each utility in 1978 as shown in Fig.7.14.

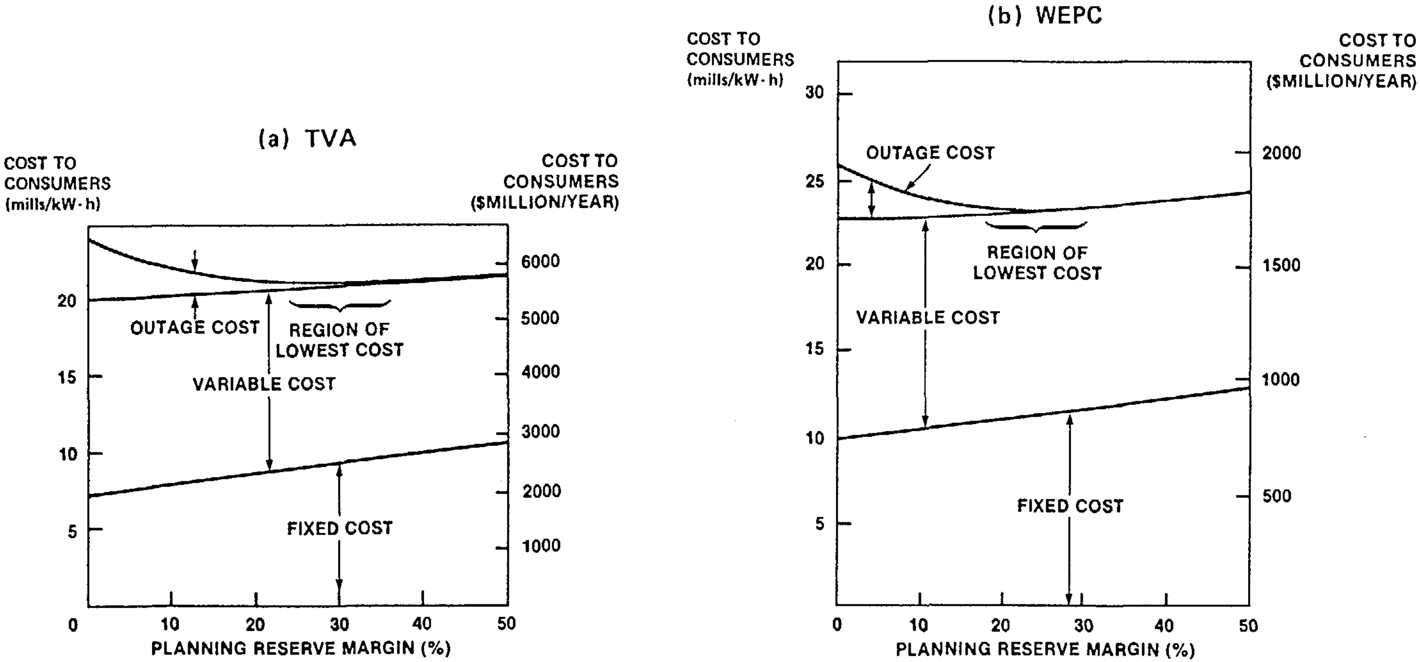
Results of the analysis of each participating utility are summarized graphically in Fig.7.15. The results of each case study are realistic but illustrative only; they do not necessarily represent proposed plans for capacity expansion of the specific utility system involved.

The overall results of the EPRI study are generally consistent with those of the Ontario Hydro study described in Section 7.4.1. As is apparent from Fig.7.15, the range of least-cost planning reserve margins is different for each utility because it depends on individual system characteristics and specific customer interruption cost assumptions made for each utility. For each utility, however, each curve of customer costs (mills/kW·h) versus planning reserve margin (%) is relatively flat near its minimum, because changes in the planning reserve margin near this point cause changes in fixed costs, variable costs and outage costs that tend to be mutually compensating. Thus, for the four case studies, the use of a planning reserve margin ten percentage points higher or five percentage points lower than the least-cost margin would cause only a small increase in costs to consumers. Moreover, the precise position of the least-cost point can be affected by changes in outage costs or other parameters.

Another result apparent from Fig.7.15, and consistent with Ontario Hydro's findings, is the significant asymmetry of total consumer costs when outage costs are considered. Relative to the range of least-cost reserve margins, both very high and very low planning reserve margins are costly to consumers. The rate of increase in consumer costs is much greater for planning reserve margins lower than the optimum than it is for higher reserve margins. In general, the greater rate of increase at lower than optimum planning reserves is a result of the customer outage cost component.

Indeed, for two utilities (WEPCO and TVA), system reliability, measured by outage costs, is a critical determinant of the least-cost planning reserve margin. When outage costs are not considered for these two utilities, the sum of the fixed and variable costs decreases steadily as the planning reserve margin is decreased. When outage costs are added, a cost curve emerges whose least-cost planning reserve margin depends critically on the cost assigned to unserved energy. Nominally, these outage costs were assigned as \$1.00/kW·h and \$0.10/kW·h by WEPCO and TVA, respectively. Figure 7.16 shows the results of additional analyses and highlights the sensitivity of total customer costs and optimum planning reserve margin to assumed outage cost for the WEPCO and TVA case studies. As the WEPCO outage costs were increased from \$0.10/kW·h to \$10.00/kW·h, the least-cost planning reserve margin moved from 13% to 30%. TVA's system showed even more sensitivity to outage costs because of its unusually flat load shape and 67% annual load factor. TVA's least-cost planning reserve margin shifted from 18% to 45% when outage costs were increased from \$0.05/kW·h to \$0.50/kW·h.

The total customer costs for PG&E and LILCO (unlike WEPCO and TVA) are relatively insensitive to changes in outage costs; the two utilities each have a large share of oil-fired capacity, and the installation of coal or nuclear base load capacity is critical to total future costs. Figure 7.15 illustrates how outage costs cease to be important for LILCO and PG&E above a 20% planning reserve margin, while the least consumer cost region is between 25% and 35% planning reserve. Total costs decrease from a higher planning reserve margin to the optimum range, indicating that the savings in variable costs resulting from operating technologies other than oil more than compensate for the increased fixed costs of installing these technologies.


(a) TVA
COST TO CONSUMERS (mills/kW·h)
COST TO CONSUMERS ($MILLION/YEAR)
OUTAGE COST
REGION OF LOWEST COST
VARIABLE COST
FIXED COST
0
5
10
15
20
1000
2000
3000
4000
5000
6000
10
20
30
40
50
PLANNING RESERVE MARGIN (%)
(b) WEPC
COST TO CONSUMERS (mills/kW·h)
COST TO CONSUMERS ($MILLION/YEAR)
OUTAGE COST
REGION OF LOWEST COST
VARIABLE COST
FIXED COST
5
10
15
20
25
30
500
1000
1500
2000
0
10
20
30
40
50
PLANNING RESERVE MARGIN (%)

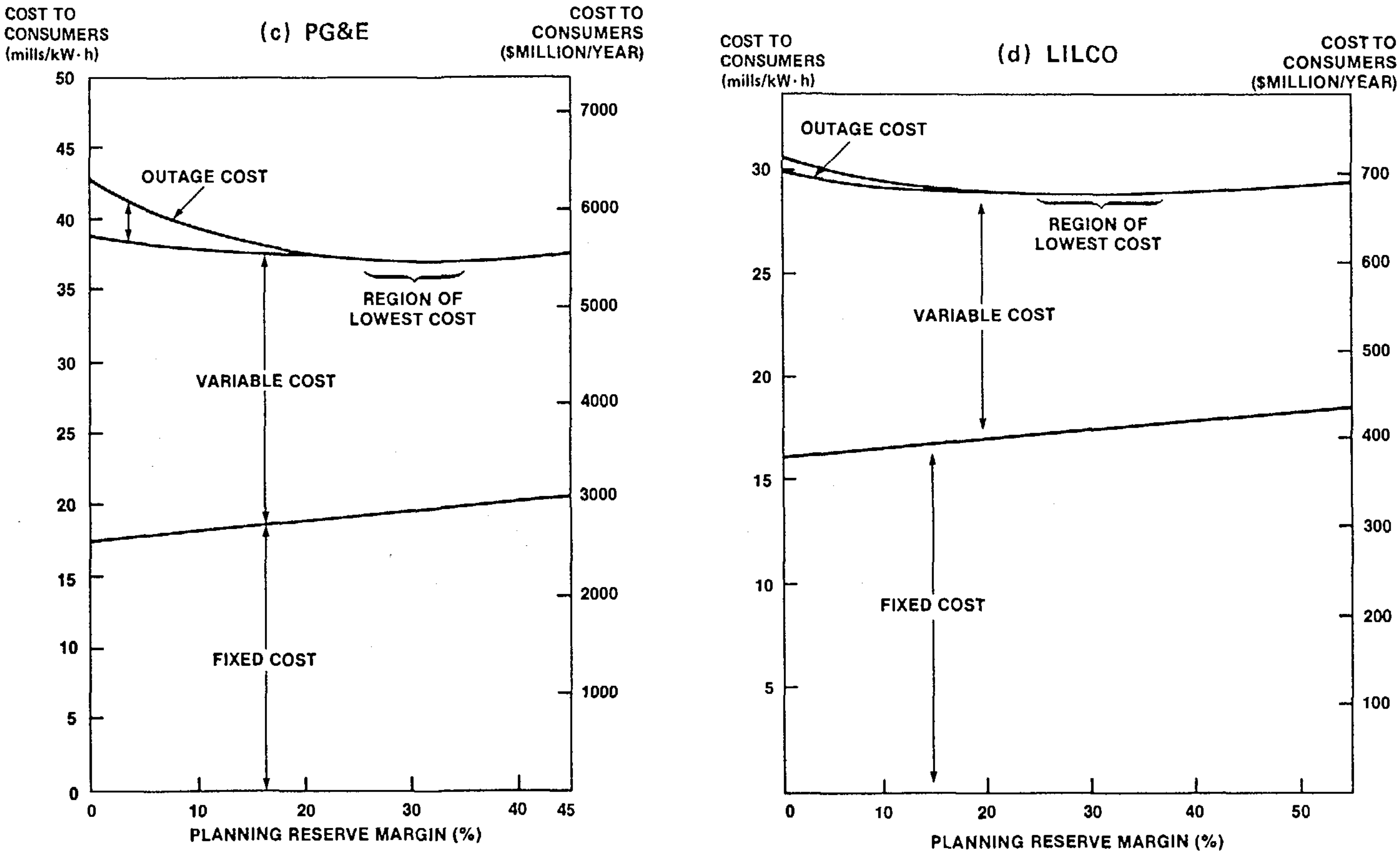


FIG.7.15. Customer costs with changes in planning reserve margin, in US $ (EPRI Study).
(a) Tennessee Valley Authority; (b) Wisconsin Electric Power Co.; (c) Pacific Gas & Electric Co.; (d) Long Island Lighting Co.

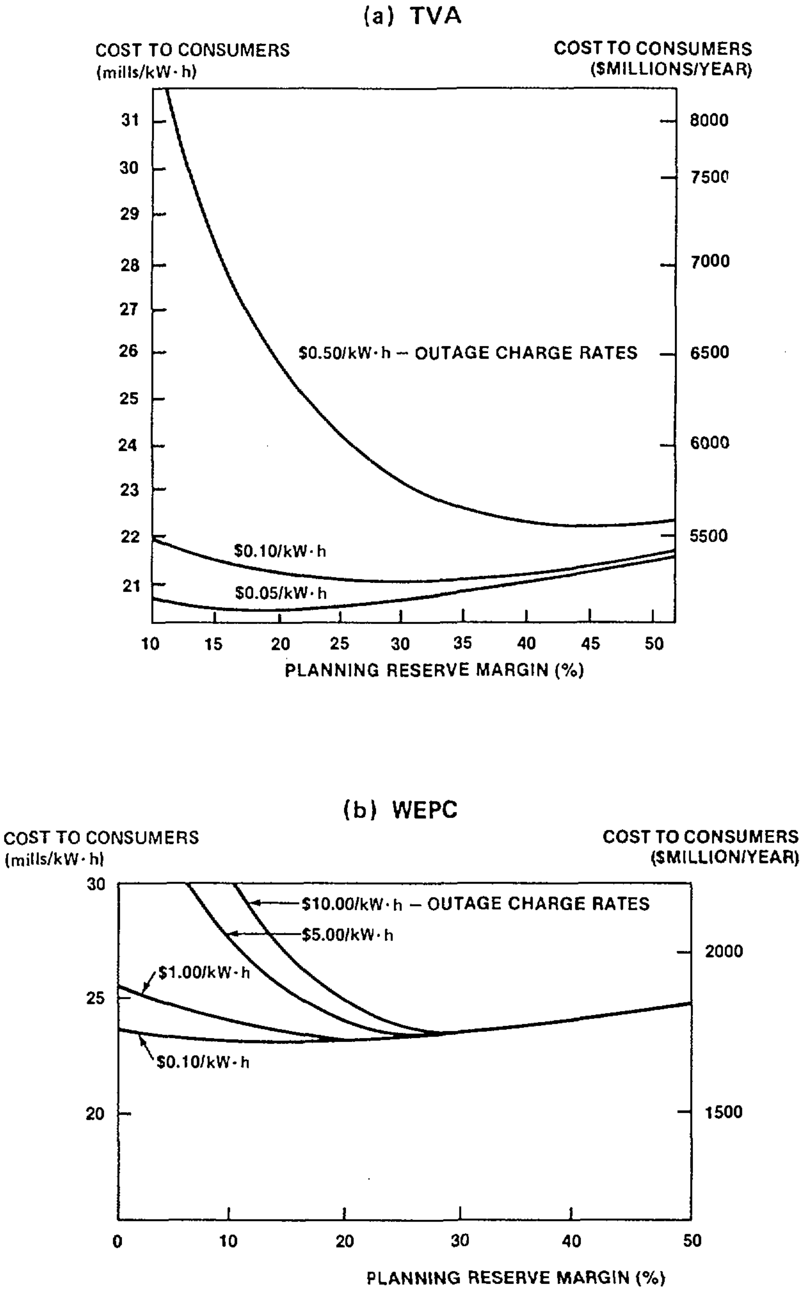


FIG. 7.16. Sensitivity to outage charge rate, in US $ (EPRI Study).
(a) Tennessee Valley Authority
(b) Wisconsin Electric Power Co.

Finally, sensitivity analysis performed as part of the EPRI study concluded that, as for Ontario Hydro, uncertainty in future demand was a significant factor in determining the least-cost planning reserve margin for each utility. When demand uncertainty was explicity included in the analysis, for example, the least-cost planning reserve margin for LILCO and PG&E increased by 4% and 7% respectively. For both utilities, this higher planning reserve margin gives protection against the high costs of operating oil-fired units in base load as would be required if demand growth is higher than expected. For the WEPCO and TVA case studies, little increase was indicated because neither utility has a large overbalance of oil-fired capacity. However, the EPRI study also concluded that even though demand uncertainty can increase the least-cost planning reserve margin, the change in total consumer cost is small in the optimum range where the cost curve is relatively flat.

7.4.3. Reliability assessment and generation planning in France

This section examines the modelling approach for reliability and generation planning used at Electricité de France (EDF) and describes the outage cost approach used by EDF for reliability assessment and generation planning. Further developments aiming at a global control of the supply and demand system as a whole are given by Lescoeur and Penz [48].

7.4.3.1. The need for a reliability criterion

EDF has to commission new facilities each year in order to meet an increasing demand and to replace oil plants. The problem of investment planning is to determine from all the possible expansion plans the one capable of meeting demand at the least cost.

This brief statement hides a major difficulty: 'meet the demand' would only be really meaningful if uncertainty did not exist. Actually, the load and the supply of power are subject to substantial random variations due to climate, hydrological conditions and forced outages of thermal plants. In recognition of these random factors, system planners accept the fact that consumers are likely to suffer a certain number of future outages. This risk can be reduced by building new facilities, and the investment decision should actually result from a balance between the need to minimize investment expenditure and the need to reduce the amount of unsupplied energy. Such a choice can be made either according to a technical or an economic criterion.

(a) Technical criterion

A technical criterion will generally consist of a maximum acceptable risk set in terms of a physical constraint. The generation expansion planning problem is then to minimize the total present worth of investment and operation costs among the expansion plans which satisfy a given reliability level. The classical reliability constraints discussed earlier in this chapter include reserve margin, LOLP, expected unserved energy, and others.

Each of these indices has its advantages and drawbacks and cannot individually provide a complete description of outages. For example, the use of the LOLP criterion based on available installed capacity does not give assurance that the energy supply will not fail to meet the energy demand by a large amount; this is the case during a dry year in a mixed hydro-thermal system.

It should be emphasized that the choice of a level of risk according to any physical index of reliability is implicitly equivalent to an outage cost (which would be the dual variable associated in the expansion planning problem with the constraint of reliability).

(b) Economic criterion

From a theoretical point of view, it appeared very early that cost-benefit analysis could be helpful to evaluate the trade-off earlier formulated between the increase in the power system supply costs and the corresponding decline in the economic costs incurred by customers because of outages. Unfortunately, estimating accurate social outage cost by inquiries among various groups of customers is a very difficult task which involves new methods and models, such as those outlined in the previous sections.

Nevertheless, because of the many advantages inherent in the outage cost method in reliability and generation expansion planning, cost-benefit analysis was adopted at an early stage by EDF planners with a first implicit estimate of the outage cost function. In this first implicit approach, the outage cost function was designed so as to ensure consistency with previous decisions based on traditional standards of reliability.

7.4.3.2. The outage cost function

An outage is conventionally defined as a situation where the national grid is not capable of meeting demand under normal operating conditions.

The prejudice incurred by a customer in a situation of outage depends on a variety of parameters defining the outage (unsupplied energy, depth of the outage, duration, frequency, possible advance warning) and on the customer himself. Among these parameters, that most relevant to investment decisions is the unsupplied energy. The implicit outage cost function used by EDF is thus a function of the amount of unsupplied energy. It is a continuous function of the unsupplied kilowatt-hours, growing with the depth of the outage.

According to the previously stated definition of the outage, the transition from a normal situation to a situation of outage for the customer is gradual: in an emergency, some generators can be overloaded and power can be purchased from neighbouring interconnected systems. The first part of the outage cost function is hence based on the internal costs of such exceptional means of satisfying demand. The second part is consistent with available external estimates of the cost of major outages. For example, on 19 Dec. 1978, the entire French electricity supply system failed for $2\frac{1}{4}$ hours in the morning, except for the part served by the Federal German power grid.

7.4.3.3. Long-run and short-run outage costs

Short-run outage costs to the customer are the costs of a particular outage given fixed electrical and energy equipment.

Long-run outage costs incurred by the customers are the costs caused by an additional outage in a given year, where the customer can allow for alternative investment in the appropriate electrical and energy equipment. For example, if customers expect a low level of reliability in the future, they might consider switching to alternative fuels to reduce their future short-term outage costs.

In the traditional approach, as long-run outage costs could hardly be accurately estimated, the outage cost function previously defined consists only of short-run outage costs. Customers' possible choices (economically measured by long-run costs) are modelled (and in some way prespecified) within the load forecast.

7.4.3.4. Advantages of the outage cost approach

The outage cost approach is *sensitive:* it permits *consistency* between the operator and the planner of the system; it allows for *decentralized* economic choices within the utility; and it is used in *marginal cost pricing.*

(a) Sensitivity

It is sensitive to small changes in the reliability, as supply and demand uncertainties are implicitly recognized in the model by considering outage costs. It allows for a meaningful ranking of the different solutions, whereas, if a physical constraint is used, two feasible solutions can satisfy the constraint in different ways and are not graded accordingly.

(b) Consistency

In a mixed hydro-thermal system, the time distribution of unsupplied energy can be modified to a certain extent by the operating rules of the reservoirs. There is a need for consistent criteria between the operation and investment levels. The outage cost approach ensures that both levels have the same criterion for decision-making.

(c) Decentralized economic studies

The MNI model, the model used by EDF, is described in Appendix B. The outage cost function is incorporated directly in the model.

(d) Marginal cost pricing

The same system of prices used for investment and operation should be used for calculating tariffs, otherwise there may be serious inconsistencies between the decisions made by the electricity producer and by his customers. With the outage cost approach, the marginal costs of supply computed in the generation expansion planning process include both capacity and energy components.

For pricing, the optimal marginal capacity costs may be allocated to different tariff periods in proportion to the corresponding expected marginal outage costs during these periods. The prices of electricity can thus be differentiated between peak days and the other periods in order to reflect the variations in the costs (including capacity costs) incurred by the producer. This gives the customer an incentive to use his electrical equipment in the public interest.

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Chapter 8

HYDROELECTRIC SYSTEM PLANNING

8.1. INTRODUCTION

Although hydroelectric generation plays a relatively small role in the overall pattern of electricity generation of industrialized countries, it is still a very important issue in hydro-dominated systems such as those of Canada and Norway, and in countries with hydroelectric subsystems, such as Bonneville Power Authority (BPA) and the Tennessee Valley Authority (TVA) in the USA.

Hydroelectric system planning is also especially relevant for developing countries. World Bank studies [1] indicate that hydroelectric generation in these countries will increase by more than 150% during 1980–1995. Even after this increase, less than 15% of the harnessable hydroelectric potential (about 7600×10^9 kW·h/a) will have been developed. Many of the power systems in developing countries are hydro-dominated. In 30 out of 69 countries studied by the World Bank, the contribution of hydroelectric sources exceeds 50% of the total generating capacity; in 15 of these countries this contribution exceeds 70% [1].

Power systems with a large hydroelectric component have some special characteristics which should be taken into account in expansion planning studies [2–4]. The fact that generation is predominantly hydroelectric implies that:

– Capital investments are high and tend to be concentrated. Also, these costs are basically associated with the needs of energy production. Once these requirements are met, the peak requirements are satisfied at low incremental costs.
– The energy production of a hydroelectric system depends on the amount of water available at each plant of the system. Since it is impossible to have prior knowledge of the future inflows, the energy benefit associated with the construction of a hydroelectric plant can only be expressed probabilistically.
– The availability of peak power in a hydroelectric plant is a function of the plant head, which in turn depends on the stored water volume. Peak offer is therefore also dependent on hydrological conditions.
– Many reservoirs are multipurpose, i.e. they have other applications besides power generation, some of which, such as flood control and irrigation, conflict with the requirements of power generation. The planning and operation of such systems should therefore be integrated with other sectors of the economy.

Other characteristics affect the transmission system:

- The hydroelectric projects tend to be located far from the main load centres, making long-distance transmission of huge power blocks an important issue.
- Since most of the peaking equipment will be installed in the hydroelectric plants, the capacity for peak modulation will be low in the main load centres, which will have to import peak power from distant hydroelectric plants.

The transmission system will thus require heavy investments since it will be mainly composed of long lines and will probably require frequent reinforcement and expensive reactive compensation owing to the need for transient stability and voltage control. For example, in the Brazilian system about 55% of the investment for 1982–1985 covers power generation, 30% covers transmission and the rest covers power distribution and other installations. An integrated generation/transmission planning approach is therefore very important for hydroelectric systems.

Finally, hydroelectric development costs are very site-specific. According to World Bank figures, typical costs are around US $1500 per kW of installed capacity, although they may range from US $900 in Colombia to more than US $5000 in Upper Volta [1]. Where coal or oil is available at international prices, the economic limit of hydroelectric power is roughly US $2000 to US $3000 per kW, but proposed schemes must be studied individually.

Given these factors, planning activities in hydro-dominated systems tend to differ from those concerned with thermal system planning, both in terms of simplifying assumptions and methodological approaches.

This chapter analyses the influence of hydroelectric characteristics on power system planning methodologies. Characteristics shared by a large number of systems are emphasized, but discussions and examples are drawn primarily from the Brazilian planning experience.

8.2. PRINCIPLES OF HYDROELECTRIC PLANTS

8.2.1. Introduction

Hydropower technology utilizes the potential energy difference between different parts of a water body at a rate which is roughly proportional to the product of water level difference, commonly referred to as *head*, and the water discharge. Hence, hydropower planning and design are directed towards increasing these two quantities by proper site selection and construction measures.

For utilization of a hydroelectric potential, two parameters are of paramount importance:

– The water flow, water mass flow rate, or water discharge Q (m^3/s);
– The height of the fall H (m).

The power (kW) of a hydroelectric power station is proportional to the product of these two parameters, as shown later.

As the water flow is variable day by day, month by month, year by year, this simple dependence shows that the available power from the hydroelectric plant is variable with time. The reservoir is the tool that can adapt in some way the naturally variable characteristics of a hydroelectric power station to the also variable demand characteristics of an electric power system.

Since the amount and reliability of discharge, as well as the possibility of creating additional head by structural methods, depend entirely on the local hydrological and geomorphological conditions, respectively, hydropower planning and design result in highly site-specific rather than standard solutions.

8.2.2. Some physical principles of hydroelectric power generation

The energy derived from the water in a conventional hydroelectric power plant is the sum of the potential energy (determined by position or elevation) and of the kinetic energy (determined by the water flow speed). The potential energy of stationary water is easily converted into kinetic energy in the form of flowing or falling water to drive a hydraulic turbine.

In an ideal hydroelectric plant, without losses, the principle of conservation of energy requires a constant energy head. The friction and heat losses of constant discharge systems are accounted for by Bernoulli's equation:

$$z_u + \frac{v_u^2}{2g} = h_l + z_d + \frac{v_d^2}{2g} \tag{8.1}$$

where the subscripts u and d refer, respectively, to upstream and downstream flow cross-section; v is the mean speed of the water; g is the acceleration of gravity; and h_l is the energy head loss between cross-sections. Figure 8.1 illustrates the energy transformations in a typical hydroelectric generating plant.

The energy line (Fig.8.1) is a line connecting the values of the remaining energy head at all points throughout the plant. The potential energy head of the reservoir water, without inflow or outflow, is represented by the centre of gravity of the water in Fig.8.1. During steady-state conditions of equal water inflow and outflow, the potential energy head is larger than z and equals h. When water flows out of the reservoir, a drop in the potential energy head equal to the velocity head $v_1^2/2g$ occurs. At any location in the penstock (see Fig.8.1), the remaining energy head consists of the elevation of the flow z_2, the pressure head h_p, and the velocity head $v_2^2/2g$. The energy head losses in a typical hydroelectric plant are shown in Fig.8.1 by decreases in the energy line. The

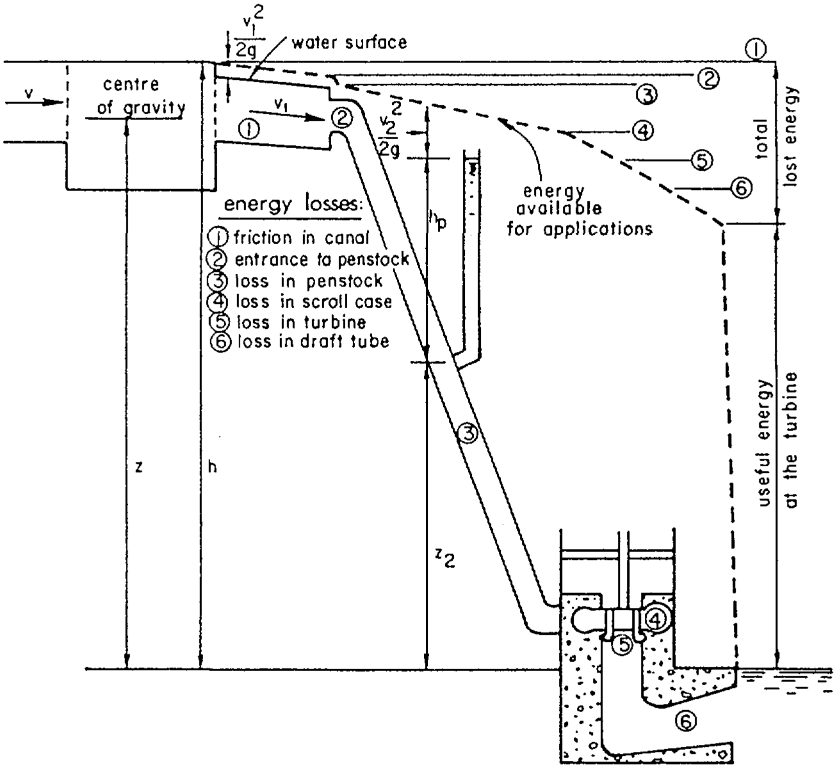

FIG. 8.1. Energy transformations in a typical hydroelectric plant (from [5], reprinted by permission of McGraw-Hill Book Co., © 1982).

total energy head, which is converted to heat and hence lost, is the sum of losses associated with friction at the entrance, bends, and elsewhere in the canal, as well as losses in the penstock, scroll case, turbine and draft tube. According to Bernoulli's theorem, Eq.(8.1), the sum of the energy head available to the turbine and the energy head losses must be equal to the original energy head (see Fig. 8.1).

The theoretical power P_t available from flowing or falling water (power in the inlet of the turbine) depends on the mass flow rate Q and on the height of the fall or the ideal energy head H_g, the gross head. Thus, the theoretical power in the entrance of the turbine is

$$P_t = gQH_g \tag{8.2}$$

where H_g is the gross head. The actual power P available at the turbine inlet is

$$P = gQH_g \left(1 - \frac{h_1}{H_g}\right) \tag{8.3}$$

where h_1 represents the total energy head losses in the plant (see Fig.8.1). The value of $(1 - h_1/H_g) = \eta_H$ is the hydraulic efficiency of a hydroelectric plant, and

$$H_N = H_g \left(1 - \frac{h_1}{H_g}\right) = H_g - h_1 \tag{8.4}$$

is the net head.

Taking into consideration the efficiency of the turbine (η_T) and that of the generator (η_G), the electrical power available in the output of the generator is:

$$P = gQH_N\eta_T\eta_G \tag{8.5}$$

If Q is expressed in m^3/s, H_N is given in metres $g = 9.8\ m/s^2$, and the power available is given in kW:

$$P\,(kW) = 9.8\ Q\,(m^3/s)\ H_N\ (m)\ \eta_T\eta_G \tag{8.6}$$

For average conditions of operation, the product $\eta_T\eta_G$ depends on the type of hydroelectric power station being considered. In plants with cross-flow turbines, 0.75 may apply and in large plants this average turbine-generator efficiency may be 0.84 or more [6].

Although, in practice, the efficiency of a turbine varies with the actual power output as a function of the design capacity, a value of $\eta_T\eta_G = 0.82$ will be assumed here for the average conditions of operations, and thus, for a quick evaluation of the available power of a hydroelectric power station, the following simpler formula can be used:

$$P(kW) = 8Q\,(m^3/s) \cdot H_N(m) \tag{8.7}$$

The energy production in kW·h during a certain time T is given by:

$$E(kW \cdot h) = P(kW) \cdot T(h) = \frac{P\,(kW) \cdot T(s)}{3600}$$

$$= \frac{9.8\ Q\,(m^3/s) \cdot H_N\,(m) \cdot T\,(s)}{3600}\ \eta_T\,\eta_G$$

$$E(kW \cdot h) = \frac{V(m^3) \cdot H_N\,(m)}{367.3}\ \eta_T\eta_G \tag{8.8}$$

where V represents the volume of water used to produce a certain energy E, or

$$V\ (m^3) = Q\ (m^3/s) \cdot T\ (s) \tag{8.9}$$

Or, using the assumed efficiency for the turbogenerating system, a simpler formula can be obtained for a quick evaluation:

$$E\ (kW \cdot h) = \frac{V\ (m^3) \cdot H_N\ (m)}{450} \tag{8.10}$$

This means that one should have a net head of 450 m so that every cubic metre available can produce 1 kW·h, or that a volume of 450 m^3 should be available so that each metre of net head can produce 1 kW·h.

Example

The maximum (nominal) discharge of a hydroelectric plant is $Q = 100\ m^3/s$; the net head is $H_N = 252$ m, the volume of the reservoir is $V = 1850 \times 10^6\ m^3$, and the average capacity factor is 35%. The installed power capacity is:

$$P\ (kW) = 8 \times 100 \times 252 = 201\ 600\ kW$$

The energy accumulated in the reservoir is:

$$E^R\ (kW \cdot h) = \frac{1850 \times 10^6 \times 252}{450} = 1036 \times 10^6\ kW \cdot h = 1036\ GW \cdot h$$

The average energy produced in the year is:

$$E\ (kW \cdot h) = 201\ 600 \times 8760 \times 0.35 = 618 \times 10^6\ kW \cdot h = 618\ GW \cdot h/a$$

This means that if the river supplying the reservoir should dry suddenly, the hydroelectric power plant could still operate with normal load for about:

$$\frac{1036\ GW \cdot h}{618\ GW \cdot h/a} = 1.68\ \text{years} = 20\ \text{months}$$

This value is sometimes also called retention capacity, defined as

$$\text{Retention capacity (year)} = \frac{\text{Useful storage } (m^3)}{\text{Annual volume of water discharged } (m^3/a)}$$

8.2.3. Types of hydroelectric power plants

In the development of head and control of discharge, various plant types can be distinguished:

- River power plants where the head is created by weirs or dams,
- Diversion schemes which basically utilize naturally available heads,
- Run-of-river plants with little or no control of discharge,
- Storage power plants with high dam and large reservoir for flow regulation,
- Pumped storage plants where water is raised during periods of low demand by means of pumps and stored for later use in the production of electricity, usually during peaks of demand.

Figure 8.2 shows two designs of hydroelectric power plants. The first is a run-of-river plant with practically no control of the natural water inflow; it has almost constant water head. The installed capacity usually matches the minimum natural inflow, and this type of plant is usually operated as base load. The second design is a hydroelectric plant with water regulation and an artificially created head. In such a plant the gross head is not constant but varies according to the immediate past power production, the volume of the reservoir and natural water inflow. Usually, the hydroelectric power management limits maximum depletion of reservoir to one third of the maximum head (H_M). Usually, as the head is relatively low, the hydraulic efficiency is high, of the order of 97%. A good approximation can therefore be made for evaluating the average net head of such installations:

(a) Maximum depletion of reservoir: one third of H_M, defining the minimum head, H_m;
(b) Average level of water corresponding to half the useful volume, i.e. at a point at one third of $H_M - H_m$;
(c) Hydraulic efficiency = 97%.

The average gross head ($\overline{H}_g$) and average net head ($\overline{H}_N$) will then be:

$$\overline{H}_g = \frac{2}{3} H_M + \frac{2}{3}\left(\frac{1}{3} H_M\right) = \frac{8}{9} H_M = 0.89 H_M \tag{8.11}$$

$$\overline{H}_N = 0.89 \times 0.97\ H_M = 0.86\ H_M \tag{8.12}$$

which is the relation usually used for the net head when estimating the power of high volume and low head hydroelectric power stations.

Between the two basic designs of hydroelectric power plants described above there is a broad range of projects. For instance, a run-of-river power station can have a small reservoir allowing a certain small regulation, or a regulating hydroelectric plant can have a high and less variable head, depending on local conditions.

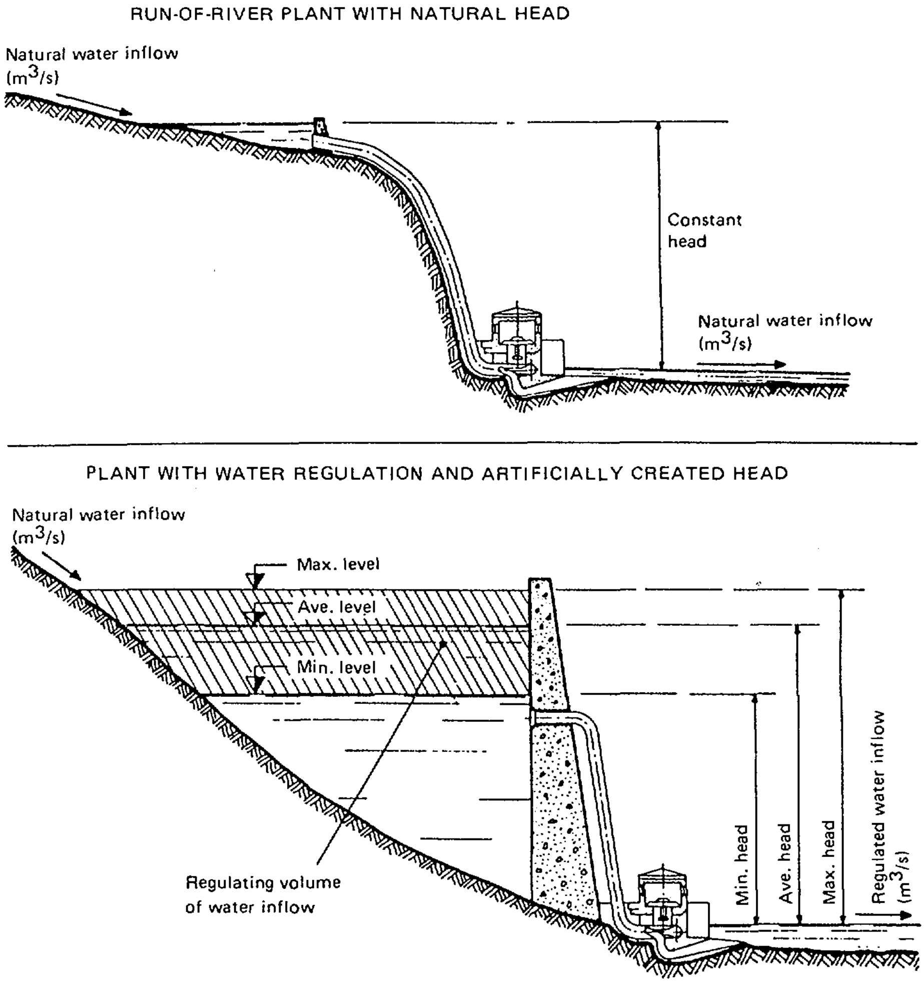

FIG. 8.2. Typical hydroelectric power plants.

The hydroelectric power plants with regulation can be regulated daily, weekly, monthly, annually or multi-annually, depending on the size of the reservoir and the inflow characteristics.

A specific type of hydroelectric plant that is very useful for storage and transfer of energy in a generation power system according to time and demand is the pumped storage plant.

Pumped storage plants generally employ two surface reservoirs located at different levels. The lower reservoir is usually an existing reservoir or natural lake. Water is pumped up to a high reservoir using off-peak electricity generated by heat-powered plants or excess electricity from the hydroelectric system and run down again in reverse mode to generate electricity when demand is high. Owing to pumping and recovery losses, approximately 4 kW·h input is required for every 3 kW·h of generation. However, in well-designed schemes, the advantages obtained by the redistribution of energy to high load periods usually far outweigh the losses.

Optimal economic operation is achieved when the incremental cost of pumping divided by the pumping efficiency is equal to the incremental cost of the offloaded thermal generation multiplied by the generating efficiency.

Pumped storage hydroelectric units have many unique characteristics which make them attractive additions to any modern system. They provide a speedy response to large changes in load, which is equalled only by the conventional hydroelectric units, and pumped storage units are just as highly reliable. They provide an excellent source of low-cost spinning reserve capacity as an insurance against major system outages and for quick startup of supply after a system breakdown. Reversible pumped storage machines may be designed to operate successfully at light loads to provide the spinning reserve capacity.

Decisions to construct pumped storage capacity are influenced mainly by the need to provide for peak demand periods and by the economic attributes of pumped storage versus other options.

A new trend in siting pumped storage power plants is to combine them with nuclear or thermal power plants in integrated power generating systems, with joint use of the reservoirs for feedwater storage and cooling purposes (USA and USSR, among others).

The nuclear pumped storage plant scheme is very effective since the nuclear plant can reach higher capacity factors operating during low demand periods for pumping water and so improve the general economy of the electrical system. Pumped storage projects may become increasingly desirable in the future as a means to accommodate intermittent power energy generation, using new energy sources (solar, wind, etc.). Pumped storage plants can operate on daily or weekly cycles.

Computations for calculating the pumping power P_p consumed by a pumped storage plant are similar to those for calculating the power of a conventional hydroelectric plant, except that in this case the efficiency is in the denominator of the power equation and the head loss is added to the gross head to obtain the net head:

$$P_p = 9.8 \frac{Q_p H_p}{\eta_p} \text{ (kW)} \tag{8.13}$$

where:

- Q_p is the total water flow being pumped (m^3/s);
- H_p is the net pumping head (same for all pumps), equal to the gross head plus the head loss (m);
- η_p is the average motor pump efficiency.

The pumping energy E_p consumed during time period T_p is calculated assuming constant H_p and η_p:

$$E_p = \frac{H_p V_p}{367.3\ \eta_p} \text{ (kW·h)} \tag{8.14}$$

where

$V_p = \int_0^{T_p} Q_p \, dt$ is the total volume of water pumped during period T_p by all pumps in the power station (m^3)

The energy E_g generated during the time period T_g and the capacity P_g for the pumped storage station can be calculated by Eqs (8.8) and (8.6), with $V_g = V_p$, assuming no leakage of pumped water.

8.2.4. Hydroelectric plant structures and layout

Hydroelectric power plants contain four structures unique to this type of plant: the forebay, penstocks, draft tubes and hydraulic turbines.

The *forebay* serves as a water storage system during times of reduced plant loads and as a water supply system during periods of load increases. If the hydroelectric plant is located at the base of a dam, the water reservoir acts as the forebay. For plants situated at the end of a canal, it can be enlarged to provide a forebay. In installations where a pipeline supplies the water, a surge tank constitutes the forebay.

The connection between the forebay and the turbine inlet or scroll case is called a *penstock*. The flow in the penstocks is controlled by forebay-penstock gates, turbine-penstock or a combination of the two.

The *draft tube* connects the turbine outlet with the tailrace (water exhaust channel) or the tailwater (free water to which the plant water is exhausted). The draft tube slows down the water at the turbine exit with a minimum of energy loss, thus allowing the removal of more energy from the water by the turbine. During normal operation, the water pressure in the draft tube is below atmospheric pressure.

Hydraulic turbines perform a continuous transformation of the potential and kinetic energy of a fluid into useful power. They are classified as either impulse or reaction turbine, depending on the type of hydraulic action involved.

In an impulse turbine, the available energy head is converted into kinetic energy by a contracting nozzle, the action taking place by the impact of the water jets on a set of spoon-shaped blades at nearly atmospheric pressure. The

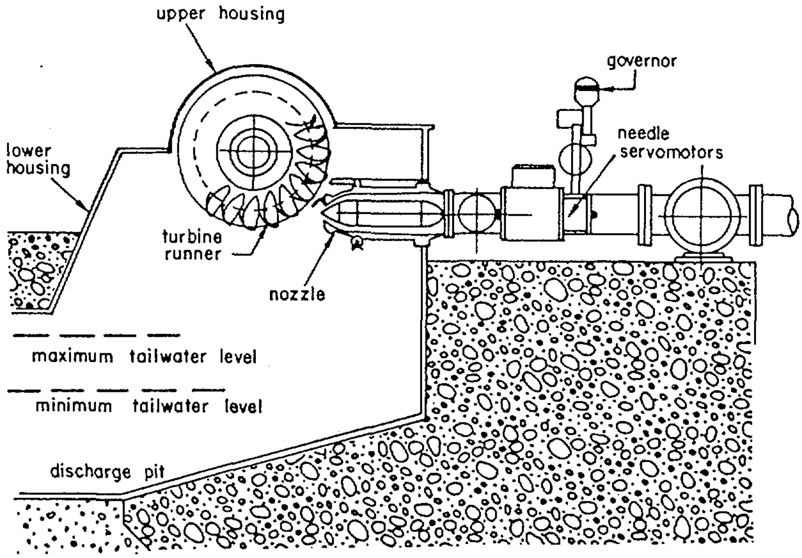

FIG. 8.3. Typical Pelton impulse-type turbine installation (from [7], reprinted by permission of Addison-Wesley Publishing Co., Advanced Book Program, © 1975).

only modern turbine of the impulse type is the Pelton turbine, also called the Pelton wheel (Fig.8.3). An impulse turbine cannot develop all of the total available head. The nozzle has to be set above tailwater level (Fig.8.3). Usually a high flood level is selected for tailwater. The vertical distance between nozzle and average tailwater is permanently lost.

In a reaction turbine, part of the total available energy head is converted into kinetic energy, the remainder being maintained as a pressure head which then decreases through the turbine passage. The pressure head is required because the water flows through the penstock, turbine and draft tube, forming a closed conduit system. The water entering the turbine exerts an impulse on the turbine runner in the direction of the flow, and the discharged water exerts a reaction on the runner in the direction opposite to the flow. Reaction turbines operate with radial, axial or mixed flow through the runner. The Francis turbine and the propeller turbine are two widely used types of reaction turbine (Figs 8.4 and 8.5).

Francis turbines are usually designed in either an axial or a mixed-flow configuration.

Propeller turbines have either fixed or adjustable blades and are usually designed for use in axial flow. The adjustable blade design is known as a Kaplan turbine. The blades may be adjusted during operation to compensate for fluctuations in power demands and operating heads.

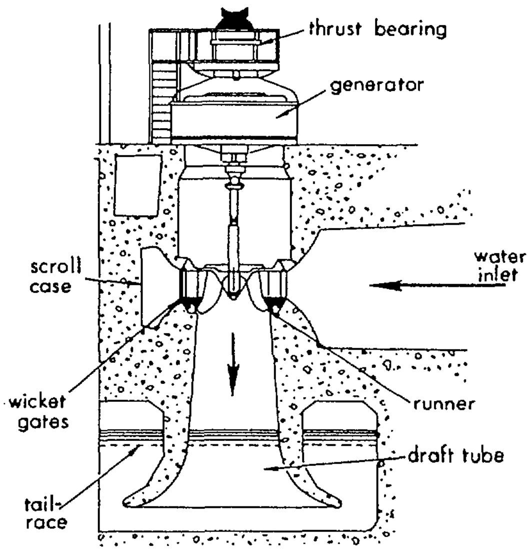

FIG. 8.4. Cross-section of a Francis reaction-type turbine (from [8], reprinted by permission of McGraw-Hill Book Co., © 1971).

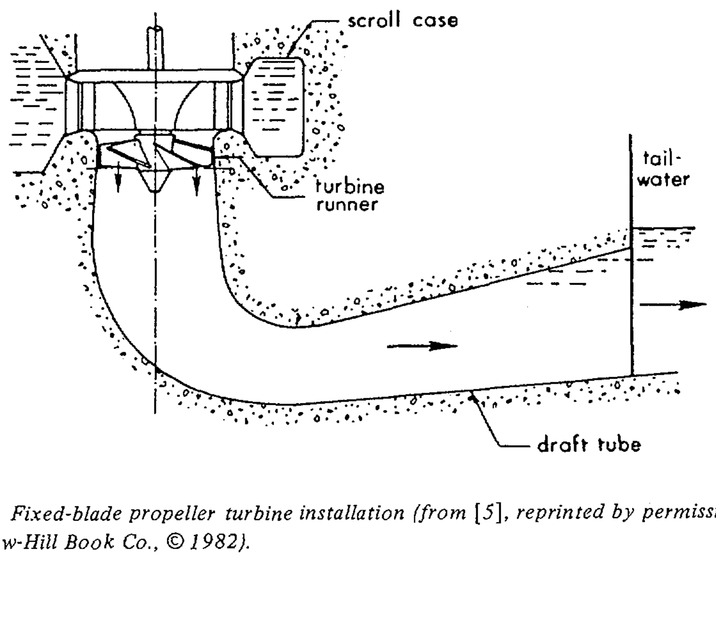

FIG. 8.5. Fixed-blade propeller turbine installation (from [5], reprinted by permission of McGraw-Hill Book Co., © 1982).

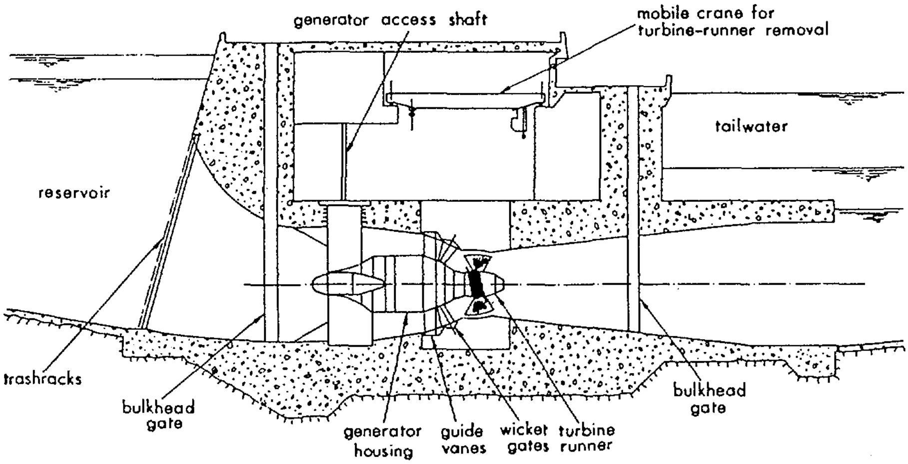

FIG. 8.6. Diagram of a bulb-type axial-flow turbine installation (from [7], reprinted by permission of Addison-Wesley Publishing Co., Advanced Book Program, © 1975).

Selection of Pelton, Francis or Kaplan turbine depends almost entirely on the available energy head.

For use in low head installations, other designs such as bulb-type and tubular turbines can be used with advantage. The bulb-type turbine and the associated generator placed in a bulb-shaped housing are placed in the centre of the water passageway (Fig.8.6). The tubular turbine design (Fig.8.7) uses an axial-flow turbine mounted in the centre of the water passageway. The turbine is connected by a shaft to a conventional horizontal-type generator located outside the water passageway.

8.2.5. Environmental impacts

Like all resource development projects, hydroelectric power development has environmental consequences, in which context there are both positive and negative effects, including:

Positive

- Swamp control;
- Landscape management, e.g. creation of lakes of recreational value;
- Flood control.

Negative

- Consequences of initial reservoir impoundment, which can involve loss of productive agricultural lands in the reservoir area;
- Disruption of existing aquatic and terrestrial ecosystems;

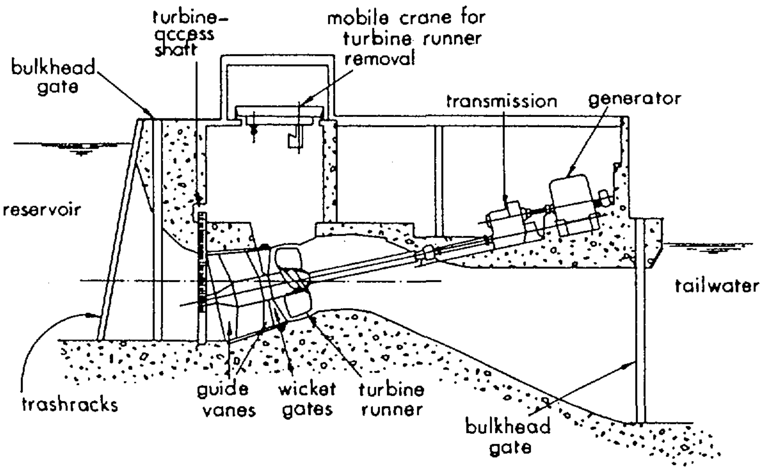

FIG. 8.7. Tubular turbine installation (from [7], reprinted by permission of Addison-Wesley Publishing Co., Advanced Book Program, © 1975).

- Loss of woods and scenic stretches on the river;
- Changes in water quality due to thermal stratification and oxygen depletion in the reservoir;
- Changes in scour and sedimentation patterns within and downstream of the reservoir and/or other perceived environmental dangers to human values and natural biological systems;
- Additional environmental impacts of long transmission lines, when required, from the project site to the area where the power is used.

The environmental impacts of hydroelectric development are particularly severe where plant operation is seasonal, weekly and sometimes daily, causing fluctuation of reservoir levels and downstream flows which affect the ecosystem.

In general, impacts on the environment can be related to physical effects (erosion of soil and sedimentation, water seepage and evaporation, modifications of water quality, hydrological regime and climate, induced seismic activity, etc.), to ecological effects (aquatic, terrestrial), to effects on human health (development and spread of diseases), and to social and economic effects (resettlement problems, safety of downstream population, flood control, agricultural water supply, transport, etc.).

8.3. CHARACTERISTICS OF HYDROELECTRIC POWER PLANTS IMPORTANT IN GENERATION SYSTEM EXPANSION PLANNING

Certain characteristics of hydroelectric power plants should be taken into consideration in generation system expansion planning studies. The most important are the following:

(1) Owing to rapid startup and flexibility for changing power output quickly, in rapid response to changes in demand, they are especially suitable for increasing the performance and efficiency of a large electric power system.
(2) They can provide spinning reserve for emergencies as well as economic and effective peak power supply.
(3) They have lower maintenance and operating costs, longer lifetime and lower outage rates than available alternatives. (On the other hand, the investment costs are usually high.)
(4) Because of low total operating costs, their production costs are particularly insensitive to future cost escalation.
(5) The best sites not yet developed are usually located far from the power-demanding centres and therefore require long and costly high-voltage electrical transmission lines.
(6) Unlike thermal plants, their output (of both power and energy) is to a certain degree uncertain since it depends on the uncertain properties of natural river flows. For supply systems in which hydroelectric sources constitute a sizeable level of capacity, the stochastic or random effects of hydraulic inflow are usually very significant.
(7) Their annual generation is, in general, limited by the annual water inflow and the size of their reservoir, if any; contrary to thermal power plants whose annual generation is mainly limited by the possible annual operating hours (availability).
(8) Economies of scale are very high. In particular, for hydroelectric power schemes with large reservoirs, the marginal cost of additional generating capacity tends to be very small.
(9) With a total annual firm energy output limited for hydrological reasons and usually small marginal cost of capacity, it follows that, at least in combined hydro-thermal systems, the most economic utilization of hydroelectric power will be obtained for small ratios of annual energy (kW·h) versus capacity (kW), i.e. for short operation durations (hours) during high demand periods (peaking). In such circumstances, hydroelectric power is competing with the least efficient steam-electric plants and with thermal peaking stations, such as gas turbines and diesel generators.
(10) In cases where the marginal costs of capacity are exceptionally high, i.e. for schemes with long penstocks or in predominantly hydro-oriented systems or in decentralized small systems, there is also economic scope for hydroelectric power plants with long operation times, i.e. base load

operations. In this case, hydroelectric power is competing with base load plants using fossil or nuclear fuels or other base load hydroelectric plants most often in combination with run-of-river plants with small or no storage reservoirs.

(11) There are three principal means of increasing the hydropower contribution within existing thermal or hydro-thermal power systems:
   (a) To increase peaking power by installing additional capacity in existing plants.
   (b) To increase total energy production by increasing total inflow through additional inter-river diversions, or by increasing storage volume through increasing the height of or reconstructing existing dams. In projects with a low utilization rate at present, total energy may also be increased by increasing the installed capacity.
   (c) To construct new hydropower schemes with due consideration of later development according to (a) and/or (b).

(12) The economics of action according to 11(a) above are highly favoured by the generally low marginal cost of additional capacity, as already mentioned. The economics of action according to 11(b) cannot be generalized since these measures are considered highly site-specific. The economics of new hydroelectric power installations according to 11(c) are characterized by relatively high investment for the first stage, with subsequently lower marginal costs for power and near-zero variable operation cost.

(13) Electricity production can be limited by alternative uses of water, e.g. for irrigation, navigation, flood control, water supply, recreation. Electric system expansion planning considering hydroelectric plants must then be adapted to other alternative uses of water. In many cases, the use of river discharges for energy purposes will also be stimulated by the need for integrated utilization of water resources for other purposes.

(14) The construction and operation of various hydroelectric power stations in the same river must take into account definite water management rules (cascade operation). This must allow for the fact that a certain volume of water has much more energetic value upstream than downstream. (The same amount of water will pass different turbines generating more power.) Also, the construction of any reservoir upstream which is or is not part of a power plant will increase the firm available energy of the plants downstream (minimum power level) available for base load.

Mathematical models are intensively used to represent these characteristics in generation and transmission planning studies. It will be seen that the production models, i.e. models that simulate the system operation, are particularly important for hydroelectric systems. Figure 8.8 is a simplified schematic diagram of the generation/transmission expansion planning models used by Centrais Elétricas Brasileiras S.A. (ELETROBRAS), a government-owned authority that co-ordinates the expansion of electric power systems in Brazil.

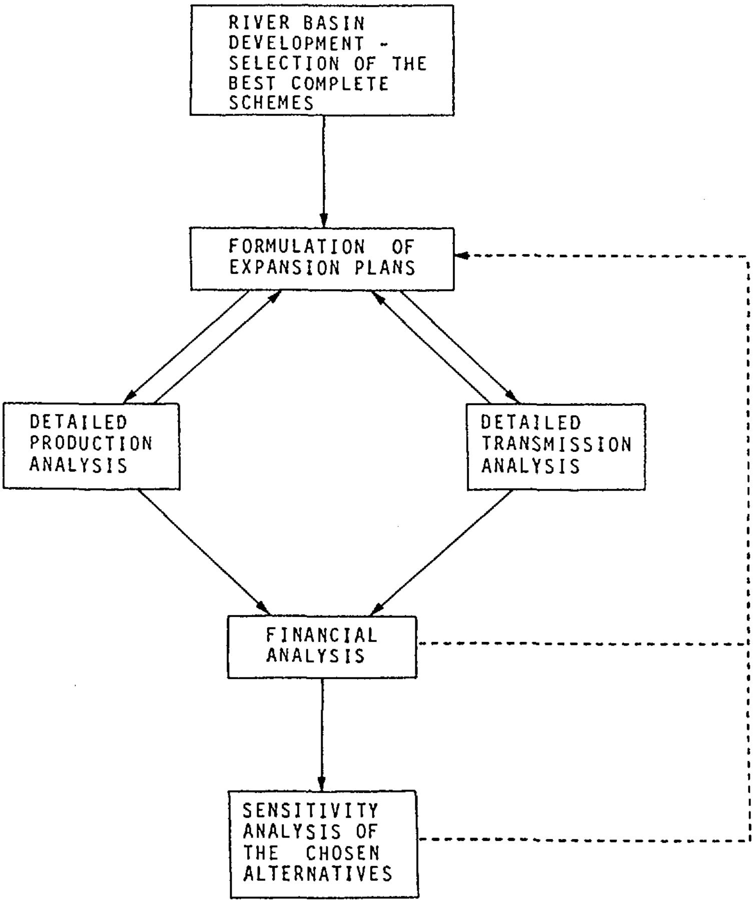

FIG. 8.8. Simplified schematic diagram of planning process.

The remainder of this chapter briefly discusses some specific aspects of hydroelectric system planning, primarily based on the Brazilian planning experience.

8.4. RIVER BASIN DEVELOPMENT

The selection of good sites for plant construction requires the evaluation of whole basins, i.e. complete schemes for hydroelectric plants. The number of possible schemes for such river basin development is theoretically infinite, but is initially reduced by the selection of good topographical sites. More schemes are eliminated by simple criteria such as minimum installed capacity per site, reservoir fill-up duration, etc. Since hundreds of alternatives usually remain to be evaluated, a simple methodology ranks them according to a cost-benefit index. The best alternatives are then studied in greater detail [9].

The benefit criterion is a function of the additional *firm power* that a new plant brings to the system. The firm power is the maximum constant load a system can meet without any deficit for the worst drought recorded in the past. Note that this drought may last for several years if the system has multi-annual reservoirs. The firm power can be evaluated by simple rules or by detailed simulation of the system operation (see Section 8.8). The choice will naturally depend on the required accuracy and on the characteristics of each region. For example, simple rules give good results in the Southeast region of Brazil, while studies in the South region usually require a more detailed simulation.

The cost of a project comprises the total capital investment cost, operation and maintenance costs, and a penalty (or bonus) associated with the lack (or surplus) of peaking capacity.

If outages are disregarded, the energy benefit of a thermal plant could be estimated in a simplified manner as its continuous generating capacity. In contrast, the energy benefit a hydroelectric plant brings to the system depends on what other plants have been built in the same scheme. An extreme case would be a pure reservoir (no associated generation) upstream of a run-of the-river (no associated reservoir) plant. If the reservoir is built alone, there is no energy benefit to the system because it has no generation capacity. If the run-of-the-river plant is built alone, the benefit is also very small because the firm power would be associated with the smallest monthly inflow recorded in the past. On the other hand, if one of the two projects is built *after* the other has been built, the energy benefit for the system would be high. In other words, the generation planning problem is *non-separable:* the benefit of a hydroelectric plant that belongs to an expansion plan depends on the expansion plan itself. This results in a difficult combinatorial problem which may be handled as described in Ref.[10].

8.5. LONG-TERM GENERATION EXPANSION PLANNING

The river basin development studies give an estimate of the siting and sizing of the candidate hydroelectric projects. It is then necessary to decide about sequence and timing, i.e. to decide in which order the projects will be constructed and the date of their completion.

The complexity of the long-term generation expansion problem for thermal systems can be illustrated by the planning models described in Chapter 10 of this guidebook. The representation of hydroelectric plants introduces an additional degree of complexity, especially in calculating production costs for a given trial plan.

In thermal systems, the supply conditions for a given period can be analysed independently of the other periods, and loading order can be determined from the generation cost characteristics of each plant. In contrast, in predominantly hydroelectric systems, the energy state of the reservoirs, and therefore their production capability, is determined by the past history of streamflows, demand evolution, equipment outages and operating policy. Production costing for hydroelectric systems is therefore not separable in time and generally requires chronological simulation. Since hydroelectric plants have no fuel costs, the determination of operation rules is also a complex problem (see Section 8.8 below).

Some of the planning models described in Chapter 10 are able to represent run-of-the-river plants and daily/weekly regulating reservoirs. On the other hand, the representation of reservoirs with large regulating capacity and of cascaded reservoir systems is still inadequate. Therefore, automatic expansion models for predominantly hydroelectric systems are used mostly for an initial formulation of the expansion plan. This plan is then subject to manual 'fine tuning' with the aid of detailed production models. For example, ELETROBRAS currently adopts a two-step approach to the formulation of the initial expansion plan:

(a) Put the candidate projects in sequence according to increasing cost-benefit indices [11]. The benefit of a hydroelectric plant is measured in terms of the additional firm power it brings to the system. The benefit of a thermal plant corresponds to its continuous generating capacity; the cost of a project corresponds to the investment cost plus the expected operation cost. In the case of hydroelectric plants, it is possible to have a bonus for the reduction in thermal generation during wet periods. These costs are estimated by simulation of the system operation (see Section 8.8). The fact that projects may be mutually beneficial, such as the pure reservoir/ run-of-the-river plants discussed in the previous section, introduces an additional combinatorial characteristic to the problem [11].
(b) The energy benefits calculated in the previous item are used as input to an optimization program that establishes the date of construction of each project [12]. The program also decides peaking capacity and power flow capacity between regions. The problem is modelled as a linear program and the objective function is to minimize the present value of investment and operation costs. The planning period is usually 30 years, divided into five-year intervals.

The plan produced by this procedure is refined to annual and monthly levels with the aid of the production models discussed in the next section.

8.6. SURVEY OF PRODUCTION ANALYSIS

In hydroelectric systems, failure to meet the load may have two different causes:

(a) *Energy deficits,* caused by the limits on the water storage in the hydroelectric plants;
(b) *Power deficits,* caused by the limits on the peak capacity of the hydroelectric plants.

Lack of energy and lack of power affect load supply in different ways. In the first case, the expected energy shortage – predictable well in advance – will give rise to a curtailment plan that dictates, possibly for months, load sheddings conveniently chosen over the daily load curve. In the second case, the lack of power will result in a forced reduction of the reserve, causing high probability of frequent and unpredictable load sheddings, mostly during peak hours. Normally these sheddings will not last longer than the peak period, and this is the case usually analysed in thermal systems.

Production analysis in hydroelectric systems is accordingly divided into two parts: *energy supply reliability* and *peak supply reliability.*

The energy state of reservoirs in predominantly hydroelectric systems is determined by the past history of streamflows, demand evolution, equipment outages and system operation. Therefore, the probabilistic evaluation of energy supply conditions requires chronological studies of the system operation along the planning period.

Equipment outages, which play a very important role in the production costing studies of thermal systems, do not affect the energy supply reliability significantly [13]. For this reason, they are usually not represented in the probabilistic simulation (they do, however, affect peak supply reliability, as will be discussed later). Ideally, demand forecasts should treat the power market as a stochastic process. In this way, instead of a single trajectory, credible demand trajectories and the associated probabilities should be considered. Owing to the difficulties of adequately evaluating these parameters, a common practice at present is to use only one demand forecast and to perform a sensitivity analysis on the expansion plan. Input for probabilistic energy supply studies are therefore the streamflow sequences (discussed in Section 8.7) and the system operating policy (discussed in Section 8.8).

The peak reliability evaluation is in turn concerned with load sheddings owing to lack of power. Although the expected unserved energy owing to lack of power may be one order of magnitude smaller than the energy not supplied owing to lack of water [2], the distinct characteristics of the two events, and the fact that incremental costs for installing the peak units are lower than those of the plant construction, make both analyses (energy and peak) very important to planners. Peak reliability evaluation for generation, multi-area and composite generation and transmission systems are discussed in Section 8.9.

8.7. STOCHASTIC STREAMFLOW MODELS

Streamflow records play a critical part in the simulation studies of the system operation. Unfortunately, the longest sequences available are of under 50 years and in most cases even less. The purpose of streamflow models is to 'extract' as much information as possible from these data. They analyse the historical record as a sample of a stochastic process and try to estimate the parameters of this process. When the process has been identified, the model can generate synthetic sequences of streamflows.

Techniques for stochastic streamflow modelling are widely available in the technical literature (see e.g. Ref.[14]). Autoregressive lag-one models, in which the probability distribution of inflow in a given period is conditioned by the observed inflow in the previous period, are especially popular owing to their simplicity and generally good performance. However, experience with the Brazilian system indicates that synthetic streamflow sequences produced by models that are apparently very similar may lead to very different results in the simulation studies [15]. For this reason, it is necessary to develop a methodology for *comparing* different stochastic streamflow models and to choose the most adequate [16]. The comparison is based on the preservation of statistics that are most relevant to power system planning. These statistics are usually related to the representation of dry periods, which are critical for energy supply reliability studies [15].

The availability of long sequences of synthetic streamflow allows the probabilistic evaluation of the system performance indices, such as the annual risk of energy shortage, the probability distribution of the power output in a given plant, etc. [17].

8.8. DETERMINATION OF THE SYSTEM OPERATING POLICY

A hydroenergetic system for generating electric energy is composed of a thermal system (conventional thermal and/or nuclear plants) and a hydroelectric system, linked to the load centres through the transmission lines, as illustrated in Fig. 8.9.

The objective of the optimal system operation is to determine a generation schedule for each plant of the system which minimizes the expected operation cost along the planning period. The operation cost includes fuel costs for the thermal units and penalties for failure in load supply [18].

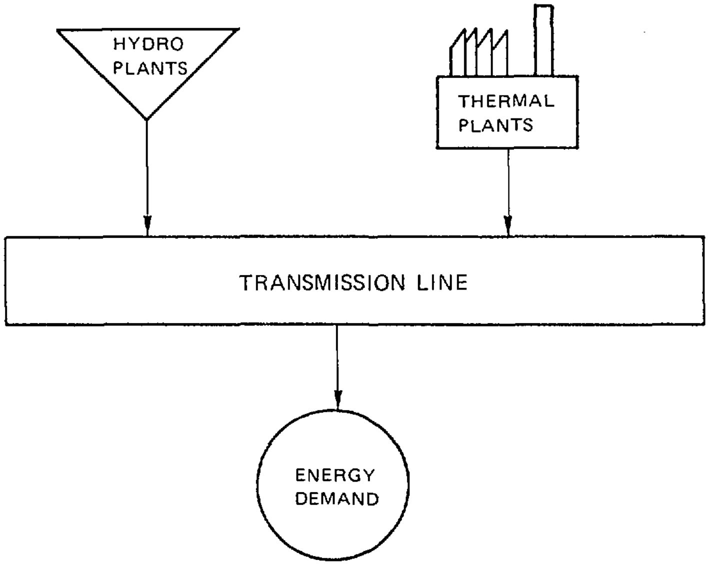

FIG. 8.9. Schematic diagram of a hydroenergetic system.

The availability of limited amounts of hydroelectric energy, in the form of stored water in the system reservoirs, makes the optimal operation problem very complex because it creates a link between an operating decision at a given stage and the future consequences of this decision. In other words, if we deplete the stocks of hydroelectric energy, and low inflow volumes occur, it may be necessary to use more expensive thermal generation in the future, or even fail to supply the load. On the other hand, if we keep the reservoir levels high by a more intensive use of thermal generation, and high inflow volumes occur, there may be spillage in the system, which means a waste of energy and consequently higher operating costs.

Since it is impossible to make perfect forecasts of the future inflow sequences and, in a certain measure, of the future load itself, the operation problem is essentially stochastic. The existence of multiple interconnected reservoirs and the need for multiperiod optimization characterize the problem as large-scale. Finally, the fact that hydroelectric units have no direct fuel cost, but an indirect operating cost measured in terms of replaced thermal costs makes the objective function non-separable. This objective function is also non-linear, owing not only to non-linear thermal cost functions but also to the product outflow times head in the expression of hydroelectric production [16].

The complexities of the operation planning problem cannot be accommodated by a single model. A chain of scheduling procedures with different planning

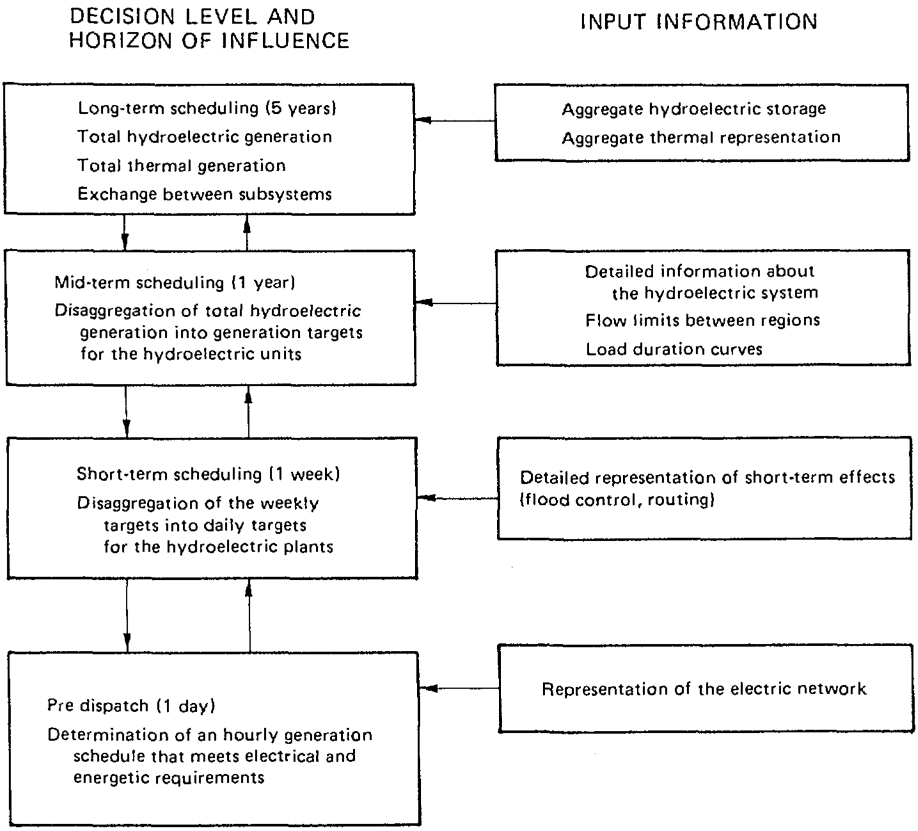

FIG. 8.10. Schematic representation of chain elements in scheduling procedures.

horizons and degrees of detail in the system representation has to be used in operation planning studies [19]. Figure 8.10 is a schematic representation of the chain elements which are briefly described below.

8.8.1. Long-term scheduling

Long-term scheduling takes into account the multi-annual evolution of reservoir storage, the probability of future energy shortages, and the expected value of thermal generation. The decision horizon is five years and the planning period is divided into discrete monthly steps. The long-term operating strategy produces, for every month, tables with the optimal proportion of hydroelectric and thermal generation in the system as a function of the aggregate hydroelectric storage, which is represented not in terms of the water volumes but in terms of the energy content of these volumes. The aggregation technique,

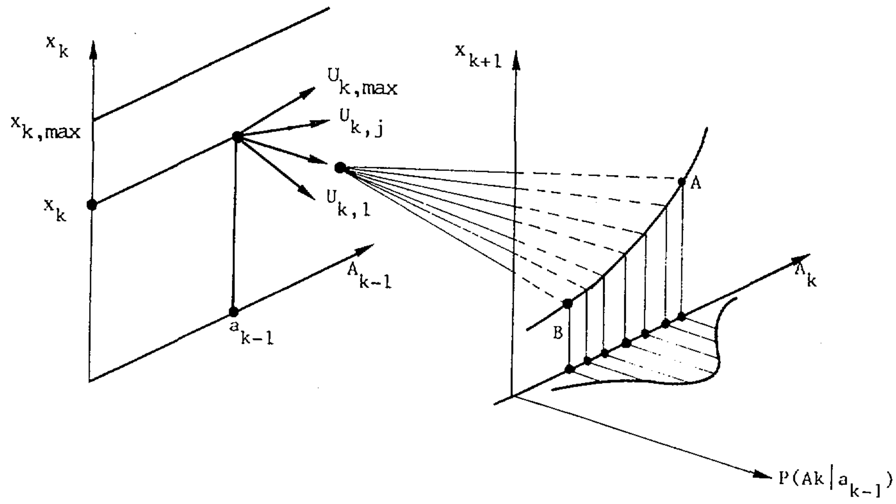

FIG.8.11. Calculation of optimal operation policy by stochastic dynamic programming. Control decisions for state (x_k,a_{k-1}) range from $U_{k,1}$ to $U_{k,max}$; the state of the reservoir in the next stage, x_{k+1}, is a function of inflow A_k.

known as *equivalent reservoir* representation [20], is based on the estimation of the energy produced by the complete depletion of the system reservoirs for a given set of initial storage volumes. Since the water head in each plant is a function of its reservoir level, the total energy produced will depend on the operation rules, which are unknown at this level of study. A simplified operation strategy is then assumed as described in Ref.[20]. A similar procedure is used to evaluate the energy content of the water inflow to the plants.

The objective function to be minimized represents the total expected operation costs, composed of thermal generation costs plus penalties for failure in load supply. The problem is solved by a stochastic dynamic programming recursion (see Fig.8.11), in which the control variable is the thermal generation and the optimal decision is a function of two state variables [21]:

(a) Stored energy in the equivalent reservoir, x_k.
(b) Hydrological trend, represented by the energy inflow during the previous month. The stochastic model supplies the distribution of inflow in month k conditioned by the inflow in month k−1—$p(A_k|A_{k-1} = a_{k-1})$.

The optimal operation policy thus obtained is input to bulk simulation models for probabilistic evaluation of system performance [22]. Figure 8.12 illustrates the risk of energy shortage in a five-year period as a function of the stored energy and the hydrological trend [23].

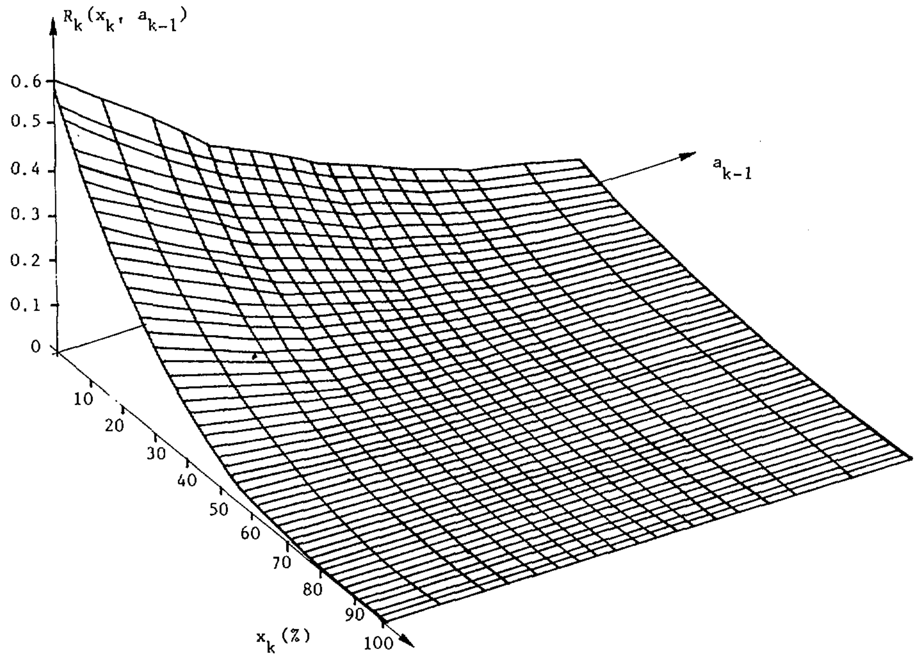

FIG. 8.12. Risk of energy shortage in the next 60 months as a function of energy storage x_k and energy inflow a_{k-1} at the beginning of month k.

The equivalent reservoir representation is reasonably accurate if the reservoirs have a large regulation capability and the region is hydrologically homogeneous, i.e. if there is a strong spatial correlation between the inflows to the different reservoirs. The region should also be electrically interconnected, i.e. the load can be supplied by the generation of any hydroelectric plant.

There are situations in which these assumptions clearly do not hold. For example, the South and Southeast regions of Brazil have quite different hydrological conditions, and the power interchange capability between the electrical systems is limited. One approach to solving this problem is to represent each region by an equivalent reservoir and take the limited power exchange between the systems as a constraint. This leads to the problem of operating reservoirs in parallel, which can be generalized to more than two subsystems.

The parallel reservoir operation problem cannot be solved by straightforward stochastic dynamic programming owing to the exponential increase of computational requirements with the number of reservoirs [24]. However, many effective approximate schemes have been suggested (e.g. [25, 26]). Although fairly recent, the method proposed in Ref.[25] has been in practical use for many years. More recently, this method has been successfully tried in the Brazilian system [27, 28]. The basic algorithm can be summarized in the following steps:

(a) Find the optimal operating policy for each subsystem independently.
(b) Simulate the simultaneous operation of all systems. Generation is scheduled with the aim of equalizing the expected future marginal costs; power flow constraints are taken into account; both historical and synthetic energy sequences can be used.
(c) Evaluate the average flow of energy for each pair of systems for each month of the simulation.
(d) Subtract from the load of each system for each month the *net* average flow calculated in (c).
(e) If convergence criterion is not met, go to (a).

8.8.2. Mid-term scheduling

Mid-term scheduling concerns the disaggregation of the total hydroelectric generation decided in the long-term level into generation targets for each of the hydroelectric plants in the system.

The target is calculated by detailed simulation models that can represent the operation of about 100 reservoirs [29]. Input for these models includes the optimal decision tables calculated at the long-term level, priorities for depletion, and rule curves that minimize spillage in the wet periods and prevent an excessive loss of head in the dry periods. This information is supplied by auxiliary models [30].

The system operation seeks to meet the load for both peak and off-peak hours. The generation targets can be calculated either by heuristic criteria or by a non-linear optimization model that minimizes the loss of stored hydraulic energy due to reservoir depletion [31].

The mid-term scheduling problem is often solved by deterministic optimization of the system operation, i.e. future inflows are assumed to be known [32, 33]. The planning horizon in these cases is one year, divided into weekly intervals. Some stochastic approaches are discussed in Refs [34] and [35].

8.8.3. Short-term scheduling

Short-term scheduling decomposes the weekly generation targets into daily scheduling targets, taking into account short-term effects of reservoir operation [36, 37].

One of the main problems associated with daily scheduling is flood control, which illustrates the problem of conflicting requirements mentioned in Section 8.1. For flood protection, the reservoir volumes should be kept as low as possible during the rainy season; for energy production, the reservoir

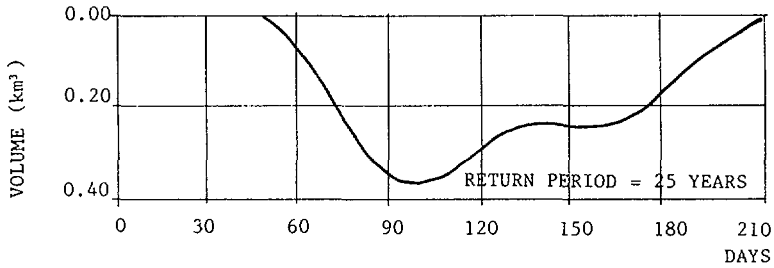

FIG. 8.13. Flood control storage for the FURNAS reservoir at Rio Grande, Brazil.

should fill up during the rainy season. As an illustration, the criterion adopted in Brazil is to minimize the loss of hydroelectric power production capability while keeping the flood risk below a pre-established target risk [38]. This problem becomes very complex in a cascaded reservoir system, where there are many alternative ways of allocating flood control storage volumes [39]. Figure 8.13 illustrates the daily evolution of the flood control storage for FURNAS, one of the main Brazilian hydroelectric plants.

8.8.4. Predispatch

The generation targets for each hydroelectric plant of the system are calculated by models that only include a very simplified representation of the electrical network. The objective of the predispatch is to produce for each plant an hourly generation schedule which does not violate hourly electrical and operational constraints and such that the sum of the hourly generations in each plant is equal to the daily generation target calculated in the short-term level of study [40]. The predispatch problem illustrates once more the difference between the fuel thermal costs and the indirect hydroelectric costs. All the 'economics' of the hydroelectric plants are given by the daily targets, since variation in the generation of a large hydroelectric plant in a given hour has a very small effect on the cost of operating this plant. A possible solution approach when the daily targets cannot be met owing to electrical constraints is described in Ref.[41].

8.9. PEAK RELIABILITY EVALUATION

8.9.1. Generation reliability

The evaluation of the peak capacity of a hydroelectric system, even in the absence of equipment outages, is directly influenced by the energy state of the

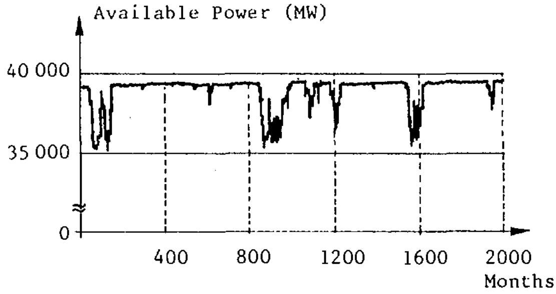

FIG.8.14. Evolution of the available power in the Brazilian South/Southeast system.

system, since it depends on the reservoir head and therefore on the level of reservoir depletion. The importance of reservoir depletion in the reduction of peak capacity can be seen from Fig.8.14, which shows the evolution of total available power (not considering forced outages) on 2000 months of simulation of the Brazilian South/Southeast system planned for 1987. It can be seen that the loss of available power reaches 5000 MW, about 12% of the total installed capacity. For other systems, this loss may go up to 20%. Equipment outages, in turn, reduce the number of working units in a given period, thus decreasing the system generating capacity.

The probabilistic evaluation of power deficits in hydroelectric systems therefore requires a specific methodology that takes into account the joint effect of reservoir depletion and equipment outages. The classical generation reliability methods, originally developed for thermal systems, are inadequate because they assume that the generating capacity depends only on forced outages.

A mixed simulation/analytical approach has been used to solve this problem [13]:

(a) Simulation of the system operation to obtain samples of the joint distribution of unit output capacities (without outages).

(b) Application of outage convolution methods to each sample, to obtain conditioned reliability indices. The system reliability is calculated as the expected value of the conditioned reliability indices.

As an example, Fig.8.15 shows the monthly LOLP values calculated for the interconnected South/Southeast regions of Brazil [13]. It is interesting to observe their seasonal variation, which is basically due to the seasonal storage variation of the system reservoirs: depletions usually occur from June to December (thus increasing LOLP values) and fill-ups from January to May (thus decreasing LOLP values).

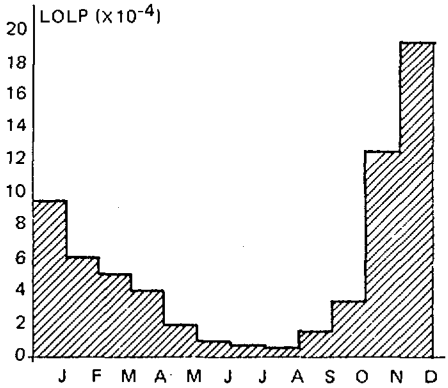

FIG. 8.15. Monthly LOLP variation in the Brazilian South/Southeast system.

8.9.2. Multi-area reliability evaluation

The study of system interconnections requires analytical tools to evaluate the reliability benefits of increased transfer capability and of alternative allocations of generation reserves among the subsystems.

The network reliability evaluation would require, in principle, the analysis of system performance for all events affecting generation and transmission capacity and for all levels of demand. Even assuming very simple models for equipment outages and load variations, the number of possible configurations increases exponentially with the size of the network and makes computational cost prohibitive even for small systems. Methods that can approximate system reliability at a reasonable cost are therefore needed.

If the power flows between interconnected subsystems can be approximated by a network flow model (only flow conservation at buses and flow limits are represented), the system reliability can be evaluated by analytical methods that are able to decompose the set of all network states into disjoint (i.e. non-overlapping) subsets of 'acceptable' (no system problems) and 'unacceptable' (loss of load) states [42]. This technique is effective only if the stochastic elements of the network are independent random variables. In thermal systems, these assumptions usually hold for line capacities and generation states. Since load levels in different regions are usually correlated, separate reliability evaluations are performed for each load level [43]. In hydroelectric systems, the energy interchange between subsystems introduces a correlation between the reservoir states and consequently a correlation between unit output capacities. For this reason, a mixed Monte Carlo/dual-state space decomposition approach is used to evaluate multi-area reliability [44]. In this approach, system states (unit output

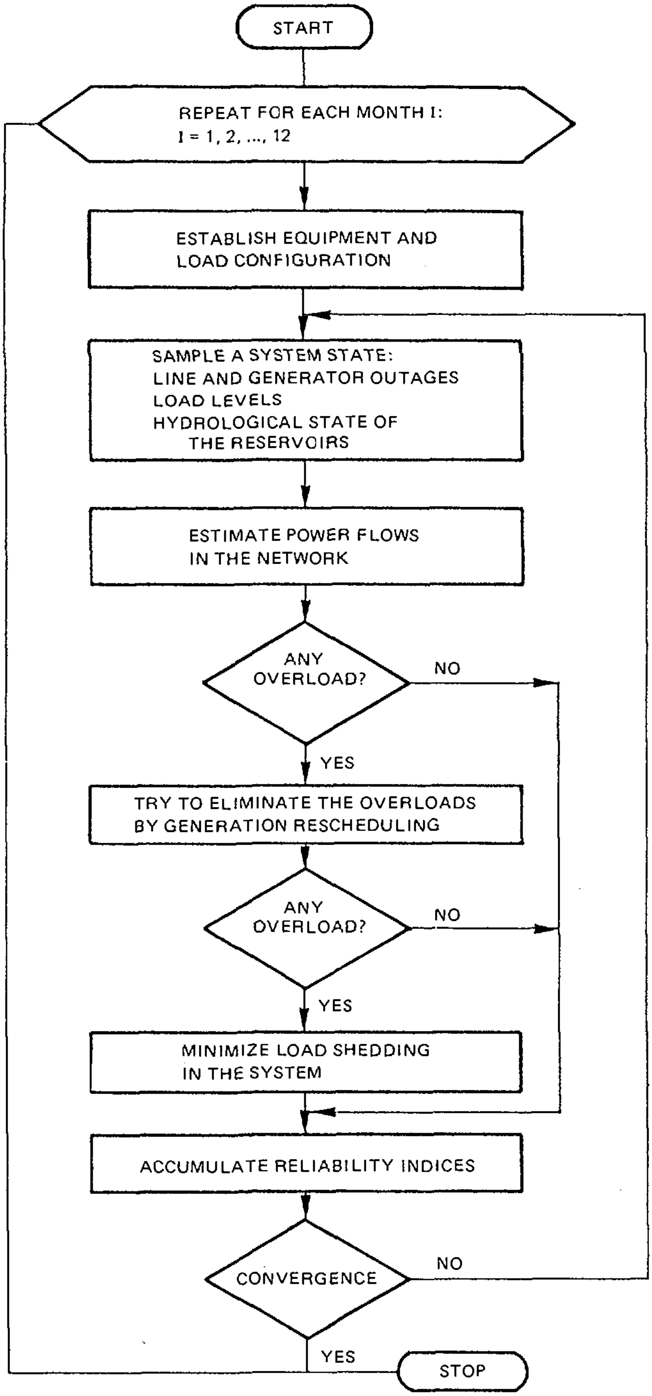

FIG. 8.16. Composite reliability algorithm.

capacities, equipment outages, load levels) are sampled from their joint probability distributions and classified as acceptable or unacceptable. The classification step is very fast because the set of acceptable states can be analytically characterized prior to the Monte Carlo sampling, and it is easy to verify whether a given state belongs to this set.

8.9.3. Composite generation/transmission reliability evaluation

An integrated generation/transmission planning approach is very important for hydroelectric systems owing to the heavy investments in transmission lines.

Composite generation/transmission reliability evaluation can be performed by Monte Carlo methods, i.e. based on the sampling of system states from their joint probability distribution [2, 45]. A system state is characterized by equipment availability (generation, lines and transformers), by the load level at each bus bar, and by the hydrological state of the system, which affects the unit output capacities of the hydroelectric plants.

Network analysis is based on the linearized power flow model (DC power flow). An optimum predispatch algorithm based on linear programming [46] is used to 'translate' line overloads in terms of load curtailment. It is thus possible to use compatible indices for generation and transmission reliability [47]. The algorithm is summarized in Fig.8.16.

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Chapter 9

POWER PLANT CHARACTERISTICS THAT AFFECT ELECTRIC SYSTEM PLANNING

The expansion of the electric system is implemented by construction of physical facilities (plants, transmission lines, etc.) that generate, transmit and distribute electric power. This chapter reviews the basic types of power plant currently used by planners and aspects of their technologies that should be considered in any plan. The first section contains a general description of the most popular technologies (excluding hydroelectric, which is described in Chapter 8). The second section describes features of power plants that affect the operation of the electric system, and the third discusses other factors that should be evaluated when executing a plan.

9.1. TYPES OF POWER PLANT

All electric power plants operate more or less in the same way. A source of energy is used either directly (e.g. gravitational potential energy of water in a hydroelectric plant) or indirectly (e.g. combustion energy to raise steam) to make a turbine rotate. The turbine is connected to an electrical generator and hence power is produced. The means by which potential or thermal energy is converted into electrical energy and the constraints that the choice of a power generation mode imposes on the system planner are the result of many factors not all of which are technical.

9.1.1. Coal-fired power plants

Coal-fired power plants (Fig.9.1) have been the main means of power generation in many countries. In the USA, for example, about 60% of the total electricity generated comes from coal combustion. Coal has the advantage of being economically transported and being burnt in units ranging in size from small peaking plants to large base load facilities. A typical coal-fired steam plant operation is described below.

The coal to be fired is usually dried by the primary airflow at the ball mill pulverizers. Between 15% and 20% of the total air is heated in the hottest sector of the air preheater as primary air, which serves to dry the coal, convey the pulverized coal to the burners and consummate the initial combustion process. The remainder of the air is preheated to a lower temperature and delivered to the burners as secondary air.

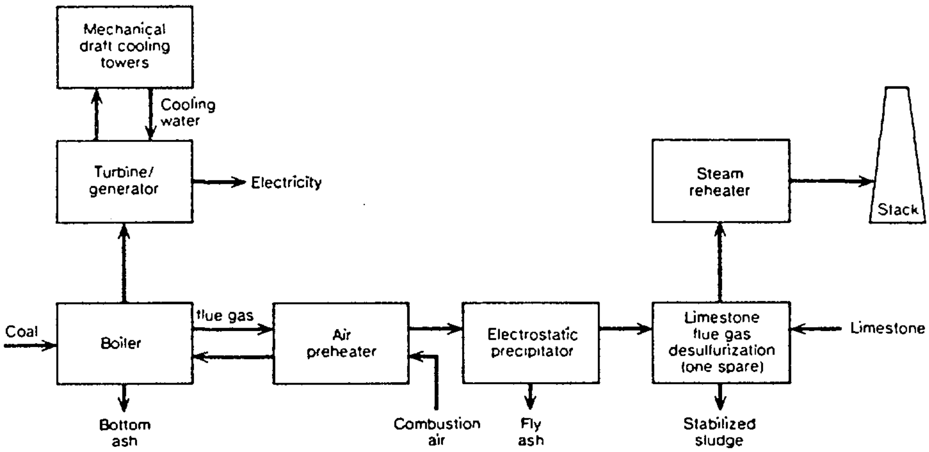

FIG.9.1. Typical conventional coal-steam plant with wet limestone flue gas desulphurization (from [1]).

The water circuitry in the steam generator provides water walls, radiant energy absorption surfaces, convection and radiant surfaces for superheating and reheating of steam, and an economizer to lower the flue gas temperature as it leaves the boiler and enters the air preheater. Slag is removed from the boiler furnace beneath the firing zone; fly ash is removed from a hopper just before entering the air preheater. These solids, representing 15% and 10% of the total ash, respectively, are sluiced to a sludge pond. The electrostatic precipitators, with an efficiency of 98.6%, collect another 75% of the total ash, leaving only about 1% in the gas flow. The collected fly ash is stored in dry silos for shipment off site. Induced draught fans follow the electrostatic precipitators.

The steam turbine is contained in four shells connected in tandem with a single generator. The low pressure stages have four parallel flows exhausting downward into a common condenser. The condenser coolant is water recirculated in a closed circuit to evaporative cooling towers or an exchanger with river or sea water. The regenerative feedwater heating cycle has four low pressure feedwater heaters, a de-aerating feedwater heater, and two high pressure feedwater heaters. Part of the steam exhausted from the high pressure turbine is used in feedwater heating, while the rest is returned to the boiler to be reheated. Part of the steam from the reheat turbine exhaust is usually used for driving the boiler feed pump. The exhausts from these drive turbines are routed to the main condenser. All other pump drives are usually driven by electric motor. The boiler feed pump and its drive are an integral part of the steam cycle.

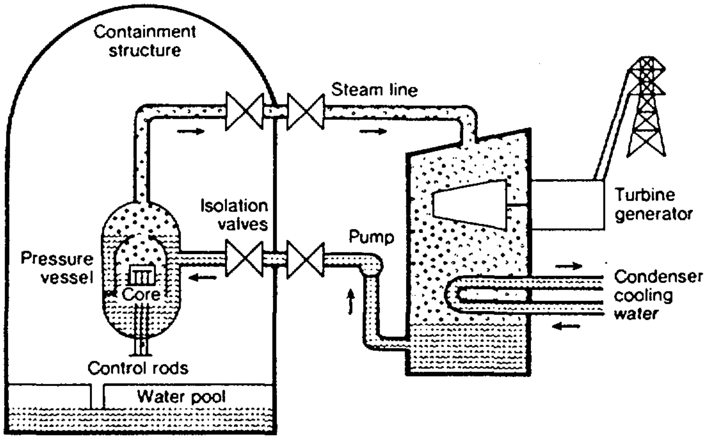

FIG.9.2. Typical BWR (from [1]).

9.1.2. Nuclear power plants

Nuclear power, first developed in the late 1940s and early 1950s, has grown rapidly in importance as a source of electric power throughout the world. The nuclear fission process as utilized to produce electricity is the result of the interaction between a neutron and the nucleus of a fissile atom, such as ^{235}U. The result is a splitting (fission) of the fissile atom, resulting in the production of energy, more neutrons, and two lighter atoms (fission fragments) which may undergo radioactive decay. An approximation of the amount of energy produced is 16.9×10^6 kJ per gram of ^{235}U undergoing fission.

The most used types of reactors for power production in the world are the boiling water reactor (BWR), shown in Fig.9.2, and the pressurized water reactor (PWR), shown in Fig.9.3. In the BWR, H_2O (normal 'light' water) is used as both coolant and moderator. At a pressure of about 70 bar, the water boils and is partially converted to steam as it flows through the reactor. Leaving the reactor, this mixture is separated into water, which is recycled back to the reactor, and steam which is sent directly to the turbines. The steam pressure of 70 bar is about one-third of what can be developed in a modern supercritical fossil-fuel fired boiler; this is primarily due to the constraints of present construction materials.

In a PWR, the coolant and moderator (consisting of liquid water) is at such high pressure (150 bar) that it remains liquid at the highest temperature (350°C) it reaches inside the reactor. This pressurized water flows to an external heat exchanger, where a secondary water system is used to generate the steam (also at about 150 bar) sent to the turbines. Again owing to constraints on construction materials, this steam pressure is lower than what would be obtained in a fossil-fuelled boiler.

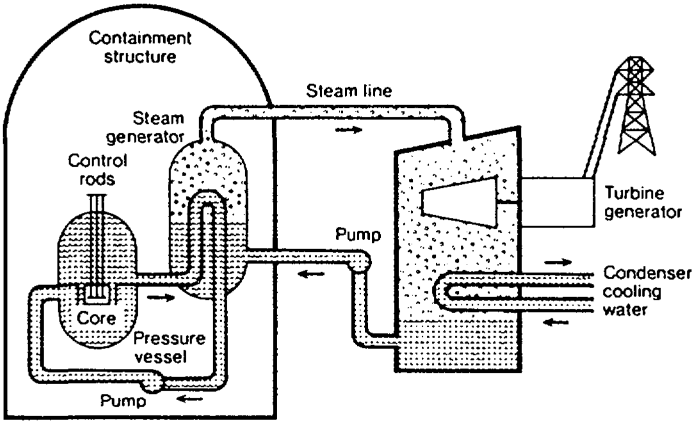

FIG.9.3. Typical PWR (from [1]).

PWRs and BWRs are also known as light-water reactors (LWRs) because they use ordinary water for both moderator and coolant. The fuel is low-enriched UO_2 (2.2–3.5%), usually canned in zirconium alloy, whereas the other structural materials of the fuel assemblies and core are made of stainless steel.

Another type of reactor used for power production is the heavy-water reactor (HWR), which uses heavy water (water where the light hydrogen is replaced by its heavier isotope, deuterium) for both moderator and coolant. The low neutron absorption of the heavy water allows the use of natural UO_2 fuel. However, the resulting lower power density of the core requires large unit size for adequate capacity and therefore a large inventory of heavy water, which increases the capital costs. HWRs with a pressure tube design have been developed in Canada and, with a pressure vessel design, in the Federal Republic of Germany. In the Canadian CANDU reactor type, the pressure vessel is replaced by a calandria, which is a tank filled with heavy water slightly above atmospheric pressure acting as a moderator, and by horizontal pressure tubes crossing the calandria and housing the fuel elements. The reactor is cooled by heavy water circulating through the pressure tubes to a steam generator.

9.1.3. Oil- and gas-fired power plants

Oil- and gas-fired power plants are very similar in design and operation to coal-fired units. Since burning gas and/or oil is relatively cleaner than burning coal, boiler tube spacing is closer and the physical size of the boiler (for the same heat release rate) is smaller.

In most gas-fired boilers, only a portion of the combustion air (the primary combustion air) is combined with the gas prior to ignition. Secondary combustion air is introduced into the furnace to complete the combustion process.

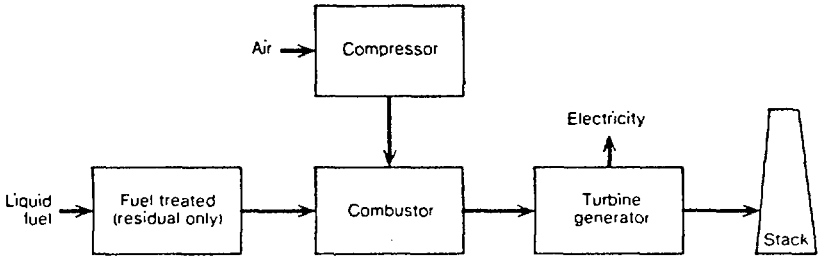

FIG.9.4. Typical conventional liquid-fuelled combustion turbine (from [1]).

With oil-fired boilers, the fuel must be vaporized before combustion can take place. The efficiency of an oil-fired plant depends therefore on both the fuel-air mixing and the atomization. A variety of atomizers, usually mechanical, are commonly employed in large power plant steam boilers. For proper atomization and combustion of certain residual fuels, a pump and heat set are sometimes necessary to raise the oil temperature and hence lower its viscosity.

9.1.4. Combustion turbines

The basic combustion turbogenerating plant (Fig.9.4) is a Brayton or joule cycle with adiabatic compression, isobaric heating and adiabatic expansion. The net 'work' of such a cycle is the difference between the work of expansion and that of compression. Turbine efficiency can be improved by:

- Addition of a regenerator to recover heat from the turbine exhaust,
- Use of intercoolers in the compressor,
- Reheating the working fluid (air or combustion gas) during expansion.

In many cases, air from the compressor is used to cool the turbine blades and fixed vanes in order to maintain a safe metal temperature. System energy losses due to this cooling air begin to affect overall efficiency at about 1640°C (turbine inlet temperature) and, at present levels of technology, become so serious at 2195°C as to make this temperature impractical.

Many modern combustion turbine power plants, especially those being considered for intermediate or base load operations, have a combined cycle operation (Fig.9.5), a system in which the hot turbine exhaust gases generate steam in a boiler to drive a steam turbine. The boiler may be designed for supplementary fuel firing, and the combustion turbine may be only a small part of the total plant. In a combined cycle unfired system, where the combustion gases from the turbine provide the total heat to the boiler, as much as 40% additional power (over and above the combustion turbogenerator system)

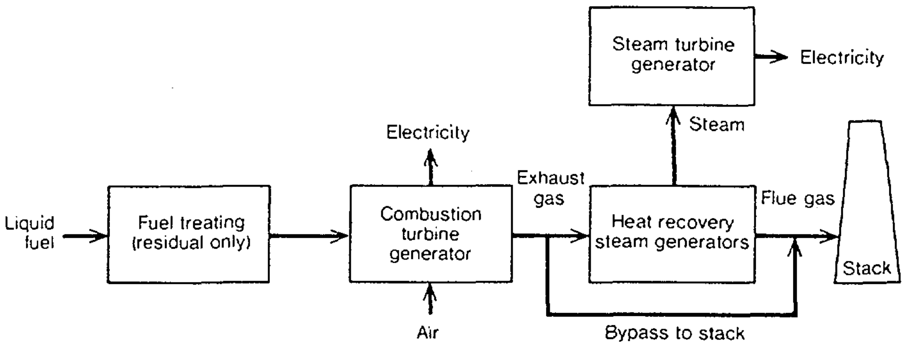

FIG.9.5. Typical conventional liquid-fuelled combined cycle (from [1]).

can be produced. This combined cycle operation can lead to efficiency 6–7% higher than that of a standard fossil-fuelled steam plant.

A combined cycle system may also be used for startups and/or coupling of peak, intermediate and base load systems. In such systems a combustion turbine, fuelled by oil or natural gas, is coupled with, for example, an oil- or coal-fired boiler. The combustion turbine can then be used for initial warm-up, to provide power for the main system during startups, and for peak load generation.

In the USA, gas turbines are primarily used for peak load operation, although refined oil seems to be economically suitable for intermittent cycle operation, which is most feasible when a combined cycle plant is constructed.

9.1.5. Diesel power plants

When the compression ratio of an internal combustion engine is high enough (between 12 and 22:1), the heat of compression causes autoignition, and no supplementary electric ignition is required. This is called the diesel cycle or compression-ignition cycle. These diesel engines use fuels of low vapour pressure ranging from fuel oils and distillates to (in some cases) crude oil. Some electrical starting aid is usually required, similar to an automobile, and the speed is controlled by varying the fuel feed rate.

In a power plant, these diesel engines, coupled with a generator, can have up to 12 cylinders and a power output of 36 000 kW(e) per engine. Diesel engines are very difficult to start under a load and must be connected to the generator by a variably coupled transmission system.

These slow-speed engines can burn a variety of liquid fuels and are ideal for peaking and intermittent operation as well as for dispersed power generation, not necessarily connected to a grid. In addition, a diesel engine generator system may prove useful (if provided with either a battery or gasoline engine generator system) as an emergency generator. This would enable a large power plant (central station) to come back on line in a short time if a forced outage should disable most of its generating capacity or if a cold start is required, as from a scheduled outage.

9.2. OPERATING CONSIDERATIONS

As discussed in Chapter 3 and shown in Fig.3.3, the planner must take into account the operating characteristics of each type of plant and its interaction with the entire system, e.g. type of duty, fuel requirements, forced outage, maintenance, startup characteristics, load-following capability, reserve capabilities and minimum load. System characteristics that can affect the way in which a plant operates are load management and load shedding practices, and other generation/transmission system constraints such as maximum allowable unit size, short-circuit levels, and load flow transient stability. These constraints are discussed below.

9.2.1. Type of duty

For maximum reliability and economy it would be desirable to have a close match between system generation capacity and system demand. Unfortunately, this is seldom, if ever, possible since predictions of system demand are not completely accurate and are affected by load swings caused by outages, industrial demands, weather patterns and even commuter traffic flow. In the USA, for example, electric utilities serving large urban areas experience peak demands corresponding to the weekday morning and evening mealtimes, when a large number of electric appliances are being used.

Similarly, large industrial complexes, which may operate on a five or six day work week, will have high startup power demands at the beginning of this period. Sudden and/or extended periods of cold or warm weather will also bring about sharp upsurges in electricity demand in areas where electric heating or cooling (air-conditioning) is used.

The power system planner should take these factors into account when considering system requirements. The use of base load, intermediate load and peaking plants, and their judicious combination, is an excellent means of duty cycle management. Table 9.I lists some of the characteristics of these plants.

It must be emphasized that the above factors are nominal and will be very site-specific. Capacity factors should be used only as the basis for conceptual designs and to represent lifetime levelized values, since the actual values will depend on outage rates and the characteristics of individual system loads.

The choice of duty cycle of a plant will affect critical design decisions by the system planner. A general rule of thumb is that no more than 10–15% of a

TABLE 9.1. PLANT CHARACTERISTICS

Duty cycle	Nominal annual capacity factor	Cost factors	Performance factor	Typical power plant type
Base	65%	Low fuel cost; high capital cost	Designed for high reliability and high efficiency	Hydroelectric, nuclear, large coal- or oil-fired units
Intermediate	30%	Intermediate to high capital cost; intermediate fuel cost	Flexible performance	Small coal-fired unit; oil-fired; large gas-fired units
Peaking	10%	Low capital cost; high fuel cost	Flexible performance; quick starting; short construction lead time	Small gas- or oil-fired boilers; gas- or oil-fired combustion turbines; diesel generators

system's capacity (peak load) should be in one unit. This is not to say that a central generating station could not have several units, each one capable of producing 10% of the projected system peak load. This criterion is designed to minimize any severe disruptions which may occur through either forced or planned unit outages. Generating unit size is discussed more fully in Section 9.2.7.

The choice of duty cycle for fossil-fuelled plants will require some consideration of fuel delivery and storage facilities. A base load or intermediate central station facility will need equipment to unload unit coal trains or tank cars (if not a mine-mouth or well-head operation). A dispersed intermediate cycle plant or a peaking plant operating on liquid fuels will need a reliable means of unloading tank trucks. In general, gas-fired units will operate direct from a pipeline and would therefore not have fuel handling and storage requirements, but the placement of these plants and the accessibility to an assured fuel supply must be taken into account.

Fuel storage capacity recommended for different duty cycle plants is shown below and should be considered in land acquisition for a new facility or in expansion of an existing unit:

Base load:	90–120 day supply at 100% capacity factor
Intermediate load:	60 day supply at 100% capacity factor
Peaking:	10–20 day supply at 100% capacity factor.

9.2.2. Fuel requirements

Fuels available or required for electric power plant operation depend on several factors: local (national) availability, in-place and planned transport networks, power plant siting, duty cycle, and fuel cost. The energy system planner must, in many cases, trade off low fuel cost against high capital cost, or high fuel cost against low, quickly constructed, capital cost (see Section 9.2.1 above for a review of some factors concerned with fuel handling and storage).

Depending on the choice of fuel and the duty cycle, sufficient land must be available for present capacity as well as planned increases in fuel storage. As an example, a 500 MW(e) coal-fired power plant will require approximately 8 ha of land for a 60 day supply of coal. A similar residual oil-fuelled plant will need 155 000 m^3 (825 000 barrels) of oil in the same period. This, in terms of storage capacity, is equivalent to eight tanks 30 m in diameter and 30 m high. Some consideration should be given, if local refinery capacity exists, to the construction of a supply pipeline directly to the power plant for a fuel supply. On-site storage will still be required to ensure continued power production in the event of a disruption in the fuel supply.

Furthermore, for fuel requirements, the systems planner should have some idea of the properties of some of the main fuels used to power electric generating stations. Table 9.II shows some typical properties and energy densities of these common fuels.

Natural gas, if stored at the plant site, will be in the form of either a highly compressed gas or liquefied natural gas (LNG). The extreme volatility of this material, coupled with its high flammability, makes proper design and layout of storage facilities extremely important. The appropriate ISO (International Organization for Standardization) codes for pressure vessel design must be rigidly adhered to, and storage tanks must be spaced (with dykes) far enough apart, from each other and from the power plant, so that an explosion would not result in a chain reaction. For large natural gas fired plants, serious consideration should be given to supplying pipelines from gas fields or remote storage locations rather than on-site fuel storage.

For nuclear power plants, fuel storage is not usually a problem, although, of course, proper planning should ensure that a supply of new fuel elements is available when it is necessary to refuel the reactor. This fresh fuel, as well as the

TABLE 9.II. FUEL PROPERTIES

Fuel	Physical state	Specific gravity	Moisture (%)	Ash (%)	Energy density (MJ/kg)
U-235	Solid[a]	10.9			16.9×10^{3}[b]
Bitum. coal	Solid	1.3	3–10	5–12	25–34
Sub-bitum. coal	Solid	1.3	12–20	5–10	21–25
Lignite	Solid	1.2	20–40	5–10	14–21
No.2 oil	Liquid	0.8–0.9	0–0.1	Nil	44–46
No.6 oil	Liquid	0.9–1.02	0.05–2.0	0.01–0.05	40–44
Natural gas	Gas	0.04	–	–	50.6

[a] As UO_2.
[b] Per kg undergoing fission.

spent fuel removed from the reactor, should be stored in a well-shielded secure building on site but well away from the reactor itself. Care should be taken in on-site handling and in transport of both fresh and spent fuel elements to ensure the safety of workers and to prevent any accidental loss of critical materials.

9.2.3. Forced outages

Forced outage is defined as a sudden loss of either generating capacity or power supply to a transmission grid. Forced outages can place sudden stresses on the grid system resulting in voltage drops, frequency variations, load shedding and, in the extreme, complete interruption of all generation. They can be caused by one or more of the following events:

- Turbine trip,
- Generator malfunction,
- Sudden cessation of fuel flow in an oil- or gas-fired unit,
- Major tube leak in a boiler,
- Fan trip,
- Nuclear reactor emergency shutdown,
- Lightning strike on a plant transformer bank or major transmission line,
- Explosion in a fuel handling or combustion system,
- Natural disaster (e.g. earthquake, tornado, tidal wave).

Data on historical forced outage statistics can be found in Appendix G.

To be considered reliable, every system should be operated so that it can continue satisfactory operation when forced outages occur. The most common difficulty is probably the sudden loss of a large generator or turbine. The remaining generators will pick up this sudden load if possible. In a reliable system the load will be picked up safely because no generator will ever be operated at 100% of rating except for short periods caused by exactly this kind of emergency. The difference between a generator's actual output and its 100% rating is its spinning reserve, which is discussed in more detail in Section 9.2.6.

In the case of severe forced outages, where the spinning reserve is not capable of picking up the entire load, some shedding will be necessary. A priority list should be prepared showing which customers will be dropped off the grid should shedding become necessary. (For more details of load shedding see Section 9.2.10.)

In extreme cases, especially where complex grids link many plants, forced outage of a major unit may cause a chain reaction, basically crippling most or all of the generating network. For proper planning, some backup or 'black start' capability should exist. Black start capability simply means the ability to restore a system to normal operation after all generation has been completely interrupted. The need for such capability has been demonstrated several times in recent years. It is relatively easy to provide black start capability within the limits of almost any capacity addition programme, and the benefits may far outweigh the additional cost and effort required.

Starting with the assumption that all rotating equipment is standing still and all switches are open, only two sources of energy are available: the substation batteries and hydroelectric installations small enough for the control gates to be operated manually. These facilities may be used to start larger units such as diesel engines and gas turbines. Small diesel engines are sometimes provided with smaller gasoline engines for starting, and larger units may be started with compressed air stored for that purpose. Most gas turbines are started by electric motors supplied from station power. One gas turbine started by an internal combustion engine will be able to start other gas turbines at the same location. One or two diesels or gas turbines will be sufficient to start a much larger steam turbine unit.

Load must be picked up in an orderly fashion to avoid disruptive overloads. Restoration of the transmission system one line at a time may facilitate this operation. Restoring service to any location may require a sequence of steps; each step takes time, and a long sequence requires a long time, a fact which has also been demonstrated several times by actual experience.

Such embarrassments can be limited and possibly avoided by adding black start capability to some existing gas turbines and diesels and providing that capability in some new peaking capacity installations. The requirement for changes or new facilities can be readily established by examining how each individual generating station might be brought into operation without using any external power source.

9.2.4. Maintenance

Maintenance can be carried out either while a unit is on line and generating power or off line during a scheduled shutdown. It is important to differentiate between routine, scheduled, maintenance and emergency repairs. Emergency repairs are what is done as the result of some event which may have caused a forced outage (see previous section). In this case, the malfunction will be repaired on a priority basis with little regard to expense, since the aim is to restore lost generation capacity as fast as possible.

Routine maintenance is performed in order to ensure that a power generation system is in good working order. In some cases, with proper planning, a good deal of maintenance may be done while a system is on line, without disrupting production. This requires the power plant to be designed with redundant and/or interconnected equipment and sufficient bypassing for on-line maintenance.

Scheduled off-line maintenance is performed once or twice a year during planned shutdowns. This is usually a major effort which must be planned for well in advance. It is during scheduled shutdowns that major pieces of equipment can be checked and overhauled, and preventive maintenance performed. This includes such major items as rebalancing turbines, inspecting generator wiring, rebricking boiler surfaces, cleaning tubes, and inspecting reactor components inside the containment vessel.

It is important in the initial planning for facility operation that a well-developed spare parts list is prepared and taken into account for construction and operating cost estimates. Particular care should be taken to ensure that critical spare parts are on hand to avoid disruption of operations while waiting for a part, particularly when parts must be shipped from a distant location.

A preventive maintenance programme should be an integral part of the planning process. This programme, as the name implies, keeps equipment in good running order and minimizes the probability of forced outages. Recommendations from equipment and system suppliers, as well as analysis of operations at existing power plants within the grid, will help to develop a good preventive maintenance programme.

9.2.5. Startup characteristics and load-following capability

The starting time of a thermal power station is the period required for combustion, raising pressure and temperature, accelerating to speed, and synchronizing. Load-following capability refers to the unit's ability to meet the changing (increasing or decreasing) load requirements of the system. As discussed in Section 9.2.1, the plants in a system can be characterized by their type of duty: base load, intermediate load or peak load plants. Because a plant is designed for a particular duty cycle, base load plants exhibit the poorest response to load changes and peak load plants show the best. A plant's load-following capability is

TABLE 9.III. LOAD-FOLLOWING CHARACTERISTICS OF GENERATING UNITS (from [2])

Type of generation	Fast spinning reserve capability: Available % of rating	Fast spinning reserve capability: Time required (s)	Maximum rate for sustained load changes	Starting time
Fossil steam	20	10	2–5%/min	Hours
Gas or oil	30	30		
Coal	15	10	2–5%/min	Hours
	20	30		
Nuclear steam (LWR)	8	10	$1\frac{1}{2}$–3%/min	Hours
	20	30		
Gas turbine:				
Heavy duty	100	5	20%/s	3–10 min
Aircraft derivative	100	5	20%/s	1–5 min
Hydro:				
High head	0	10	1%/s	1–5 min
Medium head	20	10	5%/s	3–5 min
Low head	100	10	10%/s	1–5 min

usually estimated in terms of percentage of load change per unit time in the range of 50–100% of load. A load change capability of at least 1% per minute is recommended for base load plants, while peak load plants should be able to go from a cold start to full power in 30 minutes [1].

Representative values of starting and loading times for thermal and hydroelectric generating units are shown in Table 6.IV, which is repeated here for convenience as Table 9.III. According to Marsh [2], the fast spinning reserve values are generally based on the inherent limits of thermal and mechanical time constants and assume modern design and provision for special forcing signals (which are not always applied). In particular, the reserve values for fossil steam units imply well-controlled boilers and fuel systems [2].

The characteristics of nuclear units vary widely with the type of reactor and the state of design maturity. Table 9.III shows typical values for LWRs [2].

The data given for gas turbines in Table 9.III apply to simple-cycle single-shaft units where load response is limited only by the permissible rate of temperature change and the resulting thermal stress. Infrequent emergency load change may be very rapid, although normal load changes should be much slower if excessive maintenance is to be avoided. The starting times shown are minimum values and reflect emergency conditions [2].

The load response of high-head hydroelectric plants is zero (it may even be negative) for the first few seconds. The load change rate of hydroelectric units is largely a function of the time required to safely accelerate the water filling the penstock [2].

9.2.6. Reserve capabilities

Operating reserve is a term used to describe the difference between the anticipated load and the generating capacity which can produce output within a period of time short enough to maintain acceptable frequency under credible operating contingencies. Total operating reserve is made up of spinning and non-spinning reserves.

Spinning reserve is equal to the total amount of generation available from all units synchronized (i.e. spinning) on the system minus the present load plus losses being supplied. Spinning reserve is carried so that the loss of one or more units does not cause too large a drop in system frequency. The remaining units will inherently pick up this sudden loss of generation if possible. In a reliable system the load will be picked up safely because no generator will ever be operated at 100% of rating except for short periods caused by exactly this kind of emergency.

The total spinning reserve on all units is usually determined by the size of the largest unit in operation. Some spinning reserve should be carried on each operating unit rather than being concentrated mainly on the high cost units. This will increase operating cost but also increase system reliability. The correct distribution of spinning reserve is a matter of experience, but stability studies can be helpful.

For maximum reliability, some non-spinning reserve is necessary, in addition to that already spinning. This is because a failure of one unit may use up all the spinning reserve and it becomes very desirable to recover that reserve as soon as possible in case a second sudden loss of generation should occur. Spinning reserve can be recovered in 2–5 minutes by starting gas turbines and diesels as well as most conventional hydroelectric and pumped storage hydroelectric units. These units may be operated for as long as necessary until more generation can be obtained from thermal units.

The amount of spinning and non-spinning reserve on a system is a matter of experience and judgement. Even the most economical unit on the system should carry its share of spinning reserve, and non-spinning reserve must be maintained in spite of tight maintenance schedules.

Every utility system has its own reserve criteria tailored to its needs. General rules might be as follows:

– Non-spinning reserve is 1.5 times the largest unit operating.
– Spinning reserve is half of the non-spinning reserve.
– Spinning reserve must be fully available within five minutes. Half of the gas turbines in this reserve must be spinning.
– Non-spinning reserve must be fully available within 15 minutes. Reserve on large turbogenerator sets may be limited by boiler response time.
– Strong interconnections with other systems are very helpful.

Finally, reserves must be spread around the power system to avoid 'bottling' reserves and to allow various parts of the system to run as 'islands', should they become electrically disconnected.

9.2.7. Grid/plant interactions

The economy of scale plays a major role in reducing the specific costs of installed generation, and this is particularly so for nuclear power generation. On the other hand, increased unit size has associated penalties in system requirements (increased voltage levels, higher reserve requirements, relatively lower availability, etc.) and thus there is an 'economic optimum' unit size for overall minimum cost of system expansion. As discussed in Chapter 3 (see Fig.3.3), an overall economic optimum may be obtained if input data of increased generating unit size allow for the associated penalties, for example, higher capital cost of the plant to include special transmission requirements, generally higher forced outage rates leading to higher system LOLP and O&M costs.

In addition to this economic optimum, there is what may be termed a technical limit to unit size, dictated by the permissible disturbance effects following sudden loss of the largest generating units. Sudden loss of a large generating unit and sudden pick-up of a large block of load introduce perceptible drops in the average frequency of the electric power system. Severe transient frequency drop during a few seconds (5–7 s) may endanger the overall stability of the system. It is suggested that during the first 5–7 seconds of the transient occurring after the sudden loss from the system of the largest unit, the frequency should not drop more than a maximum of 3% (if no more stringent criteria are normally applied to the system under study). The technical limit thus imposed will have a very great influence on the economics of introducing large units in a power system in case this limit is less than the economic optimum unit size (which is highly probable in relatively small power systems).

Frequency stability analysis, involving system frequency transient conditions following sudden loss of large generating units, has been found to be of prime interest in assessing this technical limit. Complete representation of this transient is very complex and calls for the modelling of system components (speed generation characteristics, machine inertia, protection relay schemes, etc.) to a high degree of detail. Analysis of the maintenance schedules of power generating units also requires detailed information about maintenance needs and time, manpower availability, detailed load forecasts, etc. However, for the purpose of long-term planning studies, simplified methods provide sufficient accuracy, bearing in mind the relatively large tolerances in data inherent in this type of study and other known limitations imposed by the analytic methodology. Such methods have been developed and are available (a simplified analysis and a computer program, FRESCO, for this assessment are described in Appendix D).

There are some rule-of-thumb criteria indicating the maximum unit size as a fraction (10–15%) of grid size or peak load. Such criteria are usually based on a degree of reliability of meeting demand which, as experience has shown, is often not met even in very large grids and which may not be required in some situations, especially in certain developing countries. In some cases, distribution grids have also been structured so that non-essential loads, e.g. irrigation pumping loads, can be shed if and when generating units drop out. However, although this rule of thumb should not be used instead of a more detailed analysis of generating unit system size, it is worth keeping it in mind when planning the grid system [3].

To achieve the economic benefits of increased unit size, it is recommended that measures such as the following be taken into consideration:

– Enlargement of the electric system by interconnections with neighbouring (national or foreign) systems;
– Sharing the power plant between two neighbouring systems (joint project, which might be international), as discussed in Section 3.1.2.4);
– Initial operation (a few years) of the power plant at a reduced power level;
– Acceptance of relatively low reliability criteria for system operation during the initial period of a nuclear power plant's operation;
– Acceptance of a limited amount of load shedding as admissible operational procedure;
– Introduction of improvements into the system, such as centralized load dispatching, increase of transmission voltage or capacity, special protective communication and control systems.

Each of these measures involves technical difficulties and costs which should be included in the overall cost-benefit evaluation. They would tend to be compensated by the potential economic benefits expected from the larger unit size and improved operational characteristics of the electric system. Whatever measures are adopted, there is still a definite limit to the maximum unit size an electric system can accept.

In highly industrialized countries, electric systems are larger, with adequate reserves, and are able to maintain stability, integrity and quality of power supply. The designs of modern commercial nuclear power plants have been developed and standardized for these conditions, where their integration into the system does not pose special problems. However, in smaller systems, where the shortage of generating capacity causes mismatch of power supply and demand, and an inadequate grid interconnection may render the system vulnerable, the commercial standardized designs may not be applicable without modifications that would allow safe and reliable operation of the plant. This could mean increases in costs.

Aspects of the electric system which require special consideration [3] are:

– Cold and spinning reserves available in the system,
– Power transmission capacity of the grid during critical conditions,
– Power control and load dispatching system,
– Voltage and frequency fluctuation control equipment,
– Probability of supply interruptions and grid disturbances.

The main technical characteristics of nuclear power plants, in particular, which are related to their integration in the electric system [3], are:

– Startup capability,
– Load change and load-following capability,
– Effects of power cycling on components and fuel elements,
– Ability to withstand externally induced disturbances,
– Minimum load.

Within limits, both the electric system and the nuclear power plant can be modified and mutually adjusted, if necessary. Recommendations on what modifications or adjustments should be undertaken are among the results expected from the feasibility study.

The IAEA has published a Guidebook dealing with these aspects in detail [4].

9.2.8. Minimum load

Minimum loads are imposed on generating units for physical and economic reasons. Minimum loading conditions for generating units are usually influenced more by the steam generator and the regenerative cycle than by the turbine. The only critical parameters for the turbine are shell and rotor metal temperature differentials, exhaust load temperature, and rotor and shell expansion. Fuel combustion stability and inherent steam generator design constraints are the major reasons for minimum load limitations [5].

Once-through boilers may require a rather large minimum flow of water and steam to prevent hot spots and tube failure. Pulverized coal-fired boilers require high minimum loads to sustain stable combustion conditions in the furnace. Although this problem can be relieved by operating the plant at light loads with a mixture of coal and oil, the result is an economic penalty if oil is more expensive than coal. Minimum operating levels may also be required to control slagging, depending on the type of coal and the furnace design [2].

Minimum loads may be as high as 50% of rating if any of the above conditions exist. In the absence of such information, 10% of rating is a practical minimum load to maintain stable control and avoid reverse power flow in the event of system frequency swings. Nuclear, gas turbine and hydroelectric units can normally operate satisfactorily at as low as 10–25% of rating, although steady state operation of nuclear units below 50% of rated capacity is rare. Pumped storage hydroelectric units are an exception since, in the pumping mode, they must usually operate near full load [2]. Appendix G lists typical technical data, including minimum load and associated heat rates, for most current technologies.

9.2.9. Load management

Because electric system loads can exhibit great daily and seasonal variations, a utility may be required to install a great deal of high fuel cost peaking generation which may be used for only a few hours each day or a few weeks in the year. It is therefore desirable to find ways in which the system peak can be flattened. *Load management* refers to any means by which load curves may be made flatter in shape, i.e. increasing the system load factor. The benefits of this are (a) greater utilization of generating equipment, which results in a lower capital investment for a given level of energy production and (b) less need to generate energy with high fuel cost peaking generation since the peaks are reduced. One study [6] has suggested that higher load factors may not always be beneficial, but it is always of interest to consider how far the annual load factor might be increased.

There are several methods of increasing the system load factor:

(a) Incentive rates could be introduced to encourage off-peak loads, perhaps facilitated by user-supplied energy storage devices. Similarly, seasonal usage may also be controlled by incentive rates.
(b) Voluntary (or, in extreme cases, mandatory) staggering of working hours and holidays for factories and offices can lower peak loads.
(c) Automatic time control of utilization equipment can be used to restrict power consumption during periods of anticipated peak loads. This scheme has been tried with some success by utilities in the USA that experience large peak loads owing to residential air-conditioners. The utility offers a financial incentive to customers in return for being able to install a control device that allows the utility to turn off that air-conditioner for 15 minutes every hour.
(d) The utility itself may want to consider developing pumped storage hydroelectric plants if the topography permits such an installation. This scheme can be very effective in flattening the load curves by, in effect, 'generating' some power at off-peak hours that will be used during peak hours.

9.2.10. Load shedding

Load shedding is the process of deliberately disconnecting preselected loads from the power system in response to a loss of power input to the system in order to maintain the nominal value of the frequency. It is used as a last resort after all other less extreme emergency operating procedures have been attempted.

Automatic load shedding by underfrequency detectors is a universally accepted method for preventing excessive frequency drops and possible system collapse or cascade tripping of power plants following a sudden loss of large power input to the system. The underfrequency relays monitor system frequency at the high voltage level by connecting the relays to the secondary winding or potential transformers in the substations.

The load shedding system automatically disconnects selected loads after the system separates into two parts or when a large generator trips out. Underfrequency relays will trip in successive steps as the frequency decays to the value for which each relay is set. Each underfrequency relay causes an auxiliary relay to open designated circuit breakers. Each underfrequency relay therefore controls a significant amount of load, and service to specific loads will be interrupted on a priority basis. Load is shed in steps at each frequency level until a balance is obtained between generation and remaining load.

The system can have from three to six levels of load shedding. The frequency at which each priority level of load will be shed is determined by calculation of relay settings. Priority levels are assigned to loads that can be shed. Large interruptible loads such as electric arc furnaces and pumping loads (e.g. pumped storage plants running in the pumping mode) should be identified and used as the first line of defence against sudden loss of large amounts of generation.

9.2.11. Generation/transmission system constraints

Combined generation/transmission system analysis is important in determining the technical constraints to be taken into account in system design and planning studies. The system analysis requires the execution of several interrelated computer studies covering load flows, fault analysis, system stability, etc., in order to determine, for example, voltage levels, circuit breaker ratings, transmission line requirements, protection system settings. The appropriate method and corresponding degree of detail required for representing the various system components will vary according to the type of problem and the application for which the solution is needed, e.g. expansion planning, system design or operation.

For long-term system expansion planning studies for which optimum strategies of system development are required, only a preliminary design of the system is sought. Load flow analysis based on system data will identify the expansion required in the transmission system, duly taking into account the load location and the siting of generating stations. Load flows must be determined for several operating conditions, including power plant outage. Short-circuit analysis will determine the need for introducing higher voltage levels.

In addition to steady state studies, analysis of the transient stability of the system is necessary. The system must be examined for all possible sources of electrical disturbance to ensure that synchronization is maintained with large plants connected to it. In particular, the system must be stable in the event of loss of the largest plant or unit when operating at full power, with due regard to system configuration and characteristics of the components.

For expansion planning studies more concerned with shorter periods of time, such as those analyses necessary during the execution of feasibility studies for a specific project, the results should give more detailed information needed for decision-making and final system design. Hence, the power system analysis should be more detailed and in greater depth then would be required for long-term expansion planning. System data, such as forecasts of load and operating conditions, unit characteristics, and power station siting, must be more accurate because errors can lead to large increases in system cost. Load flow analysis will be required for more conditions of system operation and fault. Short-circuit analysis will include not only study of the three-phase balance short-circuit, but also single line to earth, line to line and other types of faults. Not only must synchronous stability (steady state and transients) be analysed, but also voltage stability. At this stage greater emphasis should be given to considering the effects of introducing large generating units (such as nuclear power units) on the interconnected system and the effect of the system on the technical and economic characteristics of the plant.

The main functions of transmission may be categorized as follows:

(a) Bulk distribution/collection within a load generation region,
(b) Point-to-point bulk transmission from a 'remote' power station to a load centre (may be long or short distance),
(c) Interregional bulk transmission (i.e. an extension of (b) to a group of remote power stations),
(d) Interregional interconnection,
(e) International interconnection.

The normal transmission limitations encountered are excessive short-circuit levels, thermal ratings and transient stability limits. The varying importance and generalized approach to the assessment of these limits with reference to the above categories are discussed below.

9.2.11.1. Short-circuit levels

Where possible the short-circuit rating(s) of grid switchgear for the categories listed above are usually chosen with sufficient margin to cover system development into the foreseeable future, taking into account average transmission distances, load density and the expected relative proportion of local and remote power generation. Excessive short-circuit levels are most commonly encountered in very high load density areas (category (a)), particularly where the grid system is predominantly cabled (small transmission impedances). In some cases, this level can be reduced by appropriate measures such as the introduction of current limiting reactors at the generation station bus bars or system segregation, but in some other cases it has been found necessary to employ switchgear of the maximum commercially available short-circuit rating. In addition, increasing the proportion of load supplied by generation connected at the local grid voltage level will aggravate the grid short-circuit problem.

In summary, the normal solution for excessive short-circuit levels is the introduction of a higher voltage grid or other measures, such as system segregation, all requiring appropriate cost evaluation for adequate comparison of alternative expansion plans.

9.2.11.2. Load flow transient stability

To achieve a reasonable standard of supply security, the transmission grid should be capable of meeting the normal and first contingency load flow requirements throughout each plant without exceeding circuit thermal ratings, loss of system stability (system splitting), or recourse to load shedding or excessive voltage variations. It is therefore necessary to determine stability limits for steady state and transient conditions. The appropriate reinforcements to the system such as the introduction or increase of shunt and/or series compensation have to be determined.

The most common restriction to load flows in category (a) transmission is the thermal capability of circuits, and this should be the result of load flow analysis for various system-operating conditions.

The restrictions to load flows in the remaining categories of transmission can only be determined by due consideration of thermal ratios, transient stability and security criteria.

For long-term expansion planning, a simplified approach may be used as follows: for category (b) transmission, the load flow requirement may be simply estimated from the capacity of the load station less any local load to be supplied. Interregional load flow requirements (categories (b) and (c)) may be determined by a simple regional plant/load balance tabulation taking into account generating unit size and outage criteria as well as varying hydrological conditions. With all this information, the number of transmission circuits and the grid voltage necessary to meet the load flow requirements so determined for categories (b), (c) or (d) can then be estimated with sufficient accuracy, taking into account thermal ratings, transient stability limits and transmission security criteria. If the number of circuits is excessive, the possibility of a higher voltage and a step-down transformer capacity should be considered along with their costs.

A further factor in determining the capacity of category (d) transmission is the integrity of the interconnected system following faults or a sudden loss of load or generation. Experience with interconnected systems indicates that, for a reasonable stability performance, the capacity of system interconnection should be at least 10% of the installed generating capacity of the smallest of the two systems interconnected. This can be used as a guiding criterion for analysis purposes unless more detailed studies on system performance are available for the specific case.

9.3. OTHER CONSTRAINTS

Although operating characteristics play an important part in electric system planning, the planner must also consider other factors not related to plant operating characteristics, e.g. siting constraints, environmental constraints, public safety, social impact, financial constraints and licensing considerations, all of which are discussed below.

9.3.1. Siting (water, land, transport)

Choosing a site for a new power plant is an important part of electric system planning. Ideally, for maximum reliability and economy it is desirable to have the unit close to the load it will be serving, but this is seldom possible. The requirements that must be taken into account when siting a power plant are land, cooling water and transport. Commonly encountered constraints are described below. Other constraints may be characteristic of local areas and may include location of fuel supplies, available work forces, and local terrain.

The amount of land required for a new power plant depends on several considerations:

- As the system load grows, new generating facilities tend to become larger, and a capacity addition may therefore not be able to make use of an urban site which is typically surrounded by buildings or other facilities. Hence, a new unit may require a new site far from a metropolitan area in order to provide sufficient property at a reasonable cost which will satisfy building code requirements.
- Although unit size may not be a problem, the addition of all the associated facilities (e.g. fuel handling and storage, cooling water facilities, boilers and flue gas cleaning equipment, electrical switchyard, and operating and maintenance facilities) may require a substantial amount of property.

The supply of cooling water is important for thermal plants. The simple once-through flow of cooling water is being replaced by a variety of cooling methods designed to reduce the amount of cooling water required in order to leave more water available for human consumption. Cooling lakes or reservoirs have the advantage of operational simplicity and the disadvantage of increased property requirements. The property requirement can be reduced by the addition of sprays or, ultimately, cooling towers with either natural or forced draught. The use of cooling towers may be restricted by the undesired production of mist and fog. Very large cooling tower installations can produce appreciable changes in local climatic conditions.

The availability of transport is also an important constraint in siting a power plant. It should be determined whether existing roads at a potential site are adequate or need to be improved or whether new roads need to be built. Adequate rail connections are especially important to generating stations because of the heavy equipment that must be moved in during construction. Fossil-fuelled stations require railways to supply fuel. At coal-fired stations, rail connections are necessary to provide for the removal of ash and, at some newer stations, possibly scrubber sludge as well.

The location of historical and/or cultural sites must be considered when planning a new power facility. The planner should carefully examine a proposed site bearing in mind that if some artifacts are uncovered during construction, lengthy delays could result.

9.3.2. Environment

During the conceptual and design phases of a new power plant, or during expansion of an existing facility, environmental factors should be considered not only for ethical reasons but because, for example, emissions can have an adverse effect on local plant personnel, nearby communities and industries. Although provision of environmental controls will cause additional expense, they may in the long run prove their worth.

9.3.2.1. Emissions into the atmosphere

Emissions into the atmosphere are mainly of concern in the case of fossil-fuelled power plants. A properly run nuclear power plant will not emit pollutants (other than some thermal emissions from the cooling tower if there is one) into the atmosphere. The highest level of uncontrolled emissions will come from a coal-fired power plant. These are caused by impurities in the coal which manifest themselves during the combustion process. Similarly, but to a lesser extent, the same pollutants are found in emissions from other fossil fuels. These pollutants and some approaches toward dealing with them are discussed below:

(a) *Sulphur dioxide* is produced by combustion of the sulphur contained in coal. To a smaller extent, some further oxidation of a small amount of sulphur dioxide takes place to produce sulphur trioxide. In high ambient concentrations, sulphur dioxide harms human respiratory systems and can cause extensive crop damage. There is also a growing chain of evidence that emission of sulphur dioxide from fossil-fuelled power plants, through an atmospheric transformation, is linked to long-range acidic deposition. There are several options for reducing sulphur dioxide emissions. In some cases it is possible to remove all or part of the sulphur in the fuel by precombustion treatment, which can take the form of either coal cleaning or oil or natural gas 'sweetening'. The system planner should take fuel treatment into account when considering a source of fuel for an existing or new facility. If fuel treatment is not feasible, or if lower emissions of sulphur dioxide are required, some form of post-combustion treatment will be needed. This can be accomplished by flue gas desulphurization (FGD) systems (scrubbers), which can remove up to 95% of the inlet SO_2 from a flue gas.

(b) *Particulates* come from ash in the fuel being burned. They have been linked to a variety of lung diseases, soiling of buildings and clothing, and crop damage. There are several techniques for removing particulates from gas streams, e.g. cyclones, electrostatic precipitators, and fabric filters. They are easily integrated into fossil-fuelled plant design and are capable of removing more than 99% of the fly ash from gas streams.

(c) *Nitrogen oxides* are produced as a result of fuel combustion. They have been linked to smog (by combination with hydrocarbons) and, to a smaller extent, acid deposition. Nitrogen oxide emissions are most effectively reduced during the fuel combustion process. For gas- or oil-fired turbines, injection of water vapour (which basically lowers the flame temperature) is an effective means of reducing these emissions. Similarly, in coal-fired units, staged combustion or lean burning techniques have proved capable of reducing nitrogen oxide emissions by up to 50%.

9.3.2.2. Thermal pollution

No process is completely efficient, and thermal emissions occur in thermal power plants (fossil or nuclear). Theoretically, 3600 kJ are equivalent to 1 kW·h but, actually, conventional power plant heat rates range from 8440 to 11 600 kJ/kW·h. The difference between the theoretical and actual amounts is the thermal emission from the power plant.

This excess heat shows up as hot bottom ash (in a coal-fired boiler), as a hot flue gas exiting from a discharge stack (at 100–200°C), or as a warm discharge from a condensing system or cooling tower. The energy system planner must take this waste heat into consideration when planning a facility. Too great a temperature increase when a condensing system discharge is injected into a lake or river can result in massive fish kills. Similarly, downwash from a cooling tower could cause local fog. Proper design of combustion air preheat systems can increase a plant's efficiency and at the same time reduce the thermal emissions leaving with flue gas.

9.3.3. Public health and safety

As a result of increasing public anxiety about technology-associated risks, the system planner must take public health and safety issues into account when studying future electric generation systems. *Public health issues* deal with chronic effects (e.g. respiratory illness) experienced by the general public, while *safety issues* deal with the effects of accidents such as natural gas explosions, radioactive and/or chemical spills, and unexpected releases of hazardous pollutants. Health and safety evaluations should take into account all risks associated with each segment of the energy cycle of the technology under consideration. This means that health and safety issues from component fabrication, plant construction, fuel extraction and processing, O&M, waste disposal, and system decommissioning must be identified [7].

Furthermore, the risks from electricity generation differ among technologies not only in the magnitude but also in the manner in which impacts occur. These distinctions affect public perception of the acceptability of each risk and need to be preserved in an analysis. Catastrophic events constitute a prime example of the need for categorization. Because of the engineered low risk of occurrence for these events, the number of expected deaths per year, averaged over the lifetime of the plant, may be lower than that from more probable low-impact events. However, the public perception of the significance of these potential events may critically affect the viability of a technology [7].

9.3.4. Social impacts

Electric energy generation technologies can affect social issues in ways of which the system planner must be aware. Social impacts arising from each segment of the energy system cycle must be considered in the same ways as public health and safety issues.

Electric energy generation can affect society in several ways. First, it affects the financial and social lives of the population living near the energy system sites. Financial effects include public infrastructure costs and the effects on local employment, wages, prices and property values. Social stresses can result from rapid growth, changes in local political structure, and cultural changes. Effects such as local inflation, community structural changes and labour migration must also be investigated. Second, regulatory issues should be identified. They include deciding to what degree the Government will become involved in the regulatory process as well as building the necessary institutional infrastructure to carry out the process effectively. (A more detailed discussion of the regulatory process and licensing of power plants follows in Section 9.3.6.) Third, because many large power plants (especially hydroelectric and nuclear plants) are built on international borders, and the output of the plants is shared between countries, international issues affecting the construction and operation of these plants must be identified. Finally, the system planner should consider any other issues affecting society that may be specific to country or energy technology [7].

9.3.5. Financial implications

The financial impact of the decision to undertake a given strategy of development for the power system needs careful analysis. In many cases, and particularly in developing countries, the financing of investments is a crucial problem which, at the extreme, is more important than the cost of any single power plant or project. Capital intensive power plants such as nuclear or large hydroelectric power plants will clearly impose a higher burden on the country. The acuteness of the problem of financing these capital intensive projects will, of course, be a function of the balance of payments situation of the country concerned. This, in most cases, essentially depends on the import or export of primary energy, principally oil, and therefore alternative strategies of system development must be considered.

The financial burden of a given expansion programme may contradict the overall strategy for economic development of the country or region. An adequate financial analysis should be performed to determine all associated constraints, and this could require appropriate consideration of all costs/benefits arising from the alternative plans. The extent and emphasis of the analysis will mainly depend on the purposes of the planning study.

For long-term planning, emphasis is placed on all costs arising from each alternative plan, on the benefits and inconveniences of each plan, and on whether the cash-flow of expenditures, including inflation effects, can be supported by the national economy without jeopardizing economic development in other sectors. In some cases, certain approximations can be accepted because of the smaller importance of the risks involved.

For system planning related to a particular project (e.g. a large hydroelectric plan) or a series of projects (e.g. several gas turbine plants) the analysis becomes more complicated since the risks are greater; thus all the above factors require detailed and accurate analysis. It is also necessary to consider points such as:

(a) Financing sources, with due allowance for domestic and foreign currency requirements and domestic and foreign financing possibilities.
(b) Experience of the owner's organization in project implementation and financing, with due allowance for the effects of delay in implementation and of additional requirements due to uncertainties in cost estimates, etc.
(c) Demonstration of the financial soundness of the project by financial tests such as return on average net future assets in operation, number of times the debt service is covered by internal cash generation, and the internal rate of return.

9.3.6. Licensing

The grant of a specific licence or authorization at each major stage as work on a new generating plant progresses is another constraint that must be investigated by the system planner. Usually, only nuclear power plants, large fossil-fuelled power plants, and large hydroelectric power plants are subject to the regulatory process, but this depends on a country's government structure, legal traditions and administrative practices.

The regulatory authority is responsible for ensuring the health and safety of the general public against possible adverse effects arising from activities associated with power generation. For that purpose, the regulatory authority establishes standards, codes and criteria; the authority reviews and evaluates the safety analysis and environmental reports submitted by the utility/owner, issues licences or authorizations and conducts an inspection programme to ensure that everything conforms to established rules and regulations.

It is the responsibility of the utility/owner to apply for the necessary licences or authorizations. The equipment suppliers should provide the utility/owner with all necessary data and information to complete the licence/authorization applications, which are then reviewed and evaluated by the regulatory body.

The activities of the licensing/authorization process start simultaneously with the project activities and follow the project throughout its lifetime. Practices vary among countries, but licences or formal authorizations (permits) usually have to be issued for the site, construction and operation of the plant as well as for the plant personnel directly responsible for operating the plant.

The regulatory process will add to the lead time required to bring a new generating plant into operation. When a site is chosen, environmental impact studies may be required before site development work can begin. In some countries, public hearings are held so that the public can express an opinion on the application for a proposed activity. These hearings have often proved difficult to handle and have delayed the licensing process. Formalized procedures, including time limits for interventions, should therefore be established in order to prevent public hearings from becoming an open-ended forum for opponents.

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Chapter 10

MODELS FOR LONG-RANGE ELECTRIC SYSTEM ANALYSIS

This chapter introduces computerized models developed to assist the generating system expansion planner. First, the role of computerized models in expansion planning is described and their functions defined. Then follows a description of methodologies developed to simulate the electric generating system and calculate the optimum expansion plan. Finally, specific models are presented as examples of how the different methodologies have been implemented. A complete list of every available model is not attempted, but rather a sampling of models that have followed different approaches to the expansion planning problem.

10.1. THE NEED FOR MODELS

Until the mid-1960s, electric generating system expansion planning was relatively straightforward owing to the steady increase of load growth and the rapid and continuous technological advances in new and larger electric generating units, with little public concern about health and safety hazards. Since the late 1960s, decision-making on capacity expansion has become increasingly more complicated for a number of reasons:

- Planners have to evaluate more alternative technologies and sizes of new generating units;
- Operating costs are sensitive to type, cost and availability of fuels;
- Safety and pollution control equipment now represent a significant portion of total capital and operating costs;
- Longer construction periods;
- Uncertain load growth;
- Fluctuating and high interest rates;
- Financing uncertainties.

Planners are therefore no longer able to rely on simplistic or intuitive decision-making; they have to investigate the effect of various decision parameters and possible future changes. To help in this process, a model of the electric generating system under study can be defined. Estimates of future load growth, candidate power plants, fuels and other key factors can be introduced, from which the planner can evaluate decision parameters and the available alternatives. By developing a computer program that simulates the model, the required detailed calculations can be performed automatically for numerous scenarios.

Electric generation capacity expansion optimization programs ('capacity expansion programs' for brevity) are designed to evaluate the cost of electricity generation and the installation date of new generating plants for alternative expansion plans over a period of time, such as 15–30 years, and to find the optimum plan. The two major functions are therefore *electricity production simulation* and *capacity expansion optimization.*

There are also a number of production simulation programs that calculate the cost of operating the electric system and the reliability of the system, without any expansion optimization. Production simulation programs perform production simulation similar to capacity expansion programs but, typically, in more detail. The computing requirements for a production simulation program are usually much less than for a capacity expansion program because the former is evaluating one electric system configuration, whereas the latter is generally comparing many alternative expansion plans.

Production simulation programs and expansion optimization programs complement each other in performing a long-range generating system expansion study. Because of their smaller computing requirements and greater detail, production simulation programs are generally used to examine the results of an optimization program in more depth. They may also be used to evaluate the accuracy of optimization programs since these programs often use a less detailed model to simulate the operation of generating systems (which can affect production cost calculations, for example). If the task of a capacity expansion program is to choose from only a few alternative plans, the planning decision may be made by comparing the differences among the available alternatives by using a production simulation program.

Since both types of program simulate the operation of electric generating systems, they must both include:

- Forced outage of generating units;
- Maintenance schedule;
- Loading order, spinning reserve and commitment criteria;
- Calculation of electric production cost;
- Evaluation of system reliability;
- Hydroelectric energy inflow and reservoir operation (for electric systems with hydroelectric power plants).

Optimization programs also need the following features:

- Accounting for expenditure for installing new generating units (including fuel inventory costs and other non-depreciable capital costs);
- Methodology for calculating the optimum expansion plan, according to specified criteria.

10.2. MODELLING TECHNIQUES

10.2.1. Algorithms for production simulation

The purpose of electric production simulation is to simulate the operation of generating units, calculate the amount of energy generated by each generating unit, the production costs and the reliability of the system, taking into consideration the effect of the stochastic nature of forced outage of generating units.

There are three basic approaches to electrical production simulation: the Monte Carlo method, the probabilistic simulation method, and the derating (or equivalent capacity) method.

10.2.1.1. Monte Carlo method

With the Monte Carlo method, the simulation of system operation proceeds in chronological order. Assume, for instance, that an hour is the unit time length of simulation. To determine which generating units are on forced outage, a random number is drawn for each generating unit for each one-hour period. If the random number (normalized to the range of 0 to 1) drawn is less than the forced outage probability of the unit under consideration, then that unit is forced out during that hour. When the probability distribution of forced outage duration is also known, the time of occurrence and duration of forced outage may both be decided by random numbers.

Once it is determined which generating units are on forced outage, the production simulation for that hour becomes deterministic. The chronological order of simulation makes it possible to consider: (a) startup of cycling units, (b) an accurate simulation of pumped storage units, (c) unit commitment rule, (d) spinning reserve, and (e) effect of inter-ties. The disadvantage of this approach is that the results are always slightly different, even with the same input data, because of the use of random numbers in the model. By running the simulation a number of times, the model can converge to the actual solution. Algorithms have been developed to determine this convergence and the estimated accuracy of the solution.

To compare alternative expansion plans, some models use the same set of random numbers in the simulation of each alternative. Studies have been performed in determining the appropriateness of this method. Random number algorithms in digital computers actually generate pseudo-random numbers, which are designed to be statistically indistinguishable from 'true' random numbers. These algorithms are usually available as part of the standard software library of the computer manufacturers and are likely to be adequate for most applications. Numerous studies have compared their performance with more complex algorithms and methods for generating random numbers.

10.2.1.2. Probabilistic simulation

With the probabilistic simulation method, the chronological order of load for a period is ordered into a load duration curve, which represents a load probability function. The meaning of the load probability function is the probability that the load equals or exceeds a given value. Starting with the load probability function, a series of equivalent load probability functions are generated by a convolution process which takes into account the effects of forced outage of all the generating units in the system [1, 2]. The energy generated by a generating unit during the period represented by the load probability function can be calculated by integrating the equivalent load probability function corresponding to that generating unit and multiplying by the availability of the unit in that period (1 minus forced outage probability of the unit), and the time length of the period considered. The energy generated by a unit can also be determined as the difference between the energy not served before and after convolution of the unit in the equivalent load curve.

One advantage of the probabilistic simulation method is that the load for a long period (such as a month, a quarter or even a year) may be handled in a single load probability function. Thus, the method is more suitable for programs where repetitive calculations must be performed and it avoids the variance of results which is present in the Monte Carlo method.

The computing cost and accuracy of probabilistic simulation are affected significantly by the choice of the numerical algorithm adopted. The following three methods are most frequently used:

- Fourier series expansion [1, 2],
- Piecewise linear approximation [3, 4],
- Cumulant approximation [5, 6].

With the Fourier series expansion, the equivalent load probability functions are developed through convolutions and deconvolutions, which are performed by simple relations among the Fourier coefficients of only the same Fourier mode. The accuracy of computing the energy generated by each unit and the LOLP is good except when the LOLP becomes extremely small [3].

The piecewise linear method was proposed to calculate LOLP more accurately than by the Fourier series expansion, but the computational cost is significantly higher. The computational cost of the piecewise linear method is proportional to the number of convolutions and deconvolutions in each application. This method may, however, be used without a significant increase of computing time, in combination with the Fourier series expansion or with the cumulant method. For a large number of generating mixes that differ by only a small number of new units, the LOLP for one mix can be calculated by convolving and deconvolving only the generating units that are different from the mix for which LOLP was previously calculated. The computing cost of calculating only LOLP, without calculating energy generated, does not require a large number of convolutions and deconvolutions, and the computing requirement is, accordingly, much lower. The linear approximation method may therefore be used only for LOLP calculations, while the energy calculations are performed by the Fourier expansion or cumulant method [4].

With the cumulant method, load probability functions and forced outage probability distributions are all expressed in the form of low order cumulants. Convolutions and deconvolutions are performed by addition and subtraction of these cumulants. The number of cumulants used for the addition or subtraction at each convolution or deconvolution is much smaller than the number of Fourier coefficients. The computational cost with the cumulant method is approximately one order of magnitude smaller than with the Fourier expansion method. A negative feature of this method is that the accuracy of the LOLP and energy calculations for peaking-type units becomes poor when the forced outage rates as well as the number of units in the generating system are small [4].

10.2.1.3. Derating method

In the derating method for electric production simulation, the equivalent capacity is defined as the capacity of a unit times the availability of that unit, thus incorporating the effect of forced outage. The generating units with equivalent capacity are dispatched deterministically, so that the computational time required for this operation is very small. The disadvantage is that the energy generated by peaking units tends to be severely underestimated, while the energy generated by cycling units tends to be overestimated. Furthermore, the LOLP cannot be calculated by this approach. The derating method is often applied in combination with the probabilistic simulation method in order to reduce the computational cost of probabilistic simulation without causing a significant reduction in accuracy. In this approach, small peaking units are treated by the derating method while all other units are convolved probabilistically.

10.2.2. Algorithms for generating capacity planning optimization

In capacity expansion optimization, decisions must be made on the type, size and timing of unit additions during the planning period. The goal is to install capacity on an economic basis while maintaining system reliability. The type and capacity decision depends on how the new units are to be operated among the existing generating units. Large fossil-fired and nuclear units have large capital costs; they also have lower fuel costs than diesel and gas turbine generating units, which have high fuel costs and lower capital costs. Financial constraints, such as cash flow or capital expenditure problems, are usually not considered in capacity expansion optimization but rather are evaluated separately after the optimum expansion plan has been found. The analysis of capacity expansion plans is more complicated if uncertainty of load forecasts is considered (see Over-Under Model in Section 10.3.5).

In the remainder of this section, representative optimization algorithms used in capacity expansion programs are briefly described.

10.2.2.1. Dynamic programming

The application of dynamic programming in capacity expansion planning was advanced by the development of the WASP computer model [1], by which method the number of generating units of each type of unit considered represents the state variable, the number of new generating units added in a year represents the control variables, and one year is the unit increment of the state variable. The objective function to be minimized is defined as the total of (a) O&M costs (including fuel costs), plus (b) construction costs, (c) unserved energy costs, minus (d) salvage value of the new units added. Each cost item is escalated and discounted to the base year. It is also possible to calculate the objective function in terms of a fixed charge rate [7, 8] rather than construction costs and salvage value. The dynamic programming algorithm starts with a fixed initial condition (state), and finds the optimum expansion plan to reach each of all feasible states (generating mix) for the final year of the study period. The optimum expansion plan is the one that requires the lowest cost among all the possible expansion alternatives.

The user must be aware of a few characteristic aspects of the dynamic programming optimization when applied to capacity expansion optimization. First, constraints may be used in order to limit the number of expansion alternatives to be evaluated at a time. An iterative procedure is therefore used to find the unconstrained optimum solution (WASP constraints are discussed in Section 10.3.1 and Chapter 11). Second, the number of possible capacity mixes for each year increases rapidly as the study period increases. Therefore, the total number of different mixes to be evaluated by a dynamic programming optimization increases rapidly as the total length of the study period increases. This is accompanied by a substantial increase in computing requirements. Third, a buffer period beyond the final study year can be provided in order to reduce the effect of the model's wanting to select less capital-intensive generating units toward the end of the study period. A buffer period can add a significant number of alternatives to be evaluated, thus increasing computer requirements.

One method to alleviate this increasing number of states for the buffer period is to replace the buffer period in the dynamic programming optimization (dynamic buffer period) by a static buffer period. This assumes that the annual operation of electrical production beyond the end of the study horizon is identical to that of the final year of the study horizon (i.e. no capacity additions). The resulting total objective function is the sum of the objective function for the study horizon and the operating cost for the static buffer period. (The static buffer period is essentially identical to the static 'look-ahead' algorithm described in the next section.) The computational cost for a static buffer period is small and it substantially reduces the end effect of dynamic programming.

10.2.2.2. Year-to-year optimization

In this approach, the expansion decision is made by optimizing only for one year at a time, without referring to information about the future. Although the computing requirements for this approach are much smaller than those required for a global optimization, the approach tends to introduce less capital-intensive generating units, which are suboptimum in the long term.

To take advantage of the very short computational time for the year-to-year decision and to avoid the problem of short-sighted decision-making, static and dynamic look-ahead algorithms have been introduced [9–11]. With a look-ahead period, decisions are still made on a year-to-year basis, but the optimization for a year is made using the operational cost estimate for the look-ahead period.

With a static look-ahead algorithm, the load for the year of decision is assumed to remain constant for the subsequent look-ahead years, so the energy generation by each unit remains the same. The total generating cost during the look-ahead period is then calculated by escalating only the operating and maintenance cost. The length of the look-ahead period is a user-specified parameter (typically 5–10 years). The dynamic look-ahead method is similar to the static look-ahead method in the year-to-year decision, but now the dynamic programming optimization is applied to the look-ahead period starting at the year of decision-making. For example, if the look-ahead period is N years and the study horizon is K years, dynamic programming optimization for N+1 years is performed K times to complete the capacity expansion optimization. Although multiple executions of dynamic programming are necessary, each run of the dynamic programming is shorter than a run for the global dynamic programming optimization. The total computational requirements can thus be significantly shorter than the global dynamic programming optimization.

10.2.2.3. Linear, linear mixed-integer, and non-linear programming

There have been numerous applications of linear programming to optimizing both electric generation operation and capacity expansion [12–16], many of which have been successful. However, the use of linear programming in place of dynamic programming in a long-range capacity optimization program is still a formidable challenge because: (a) all the dependent variables should be expressed or approximated by linear functions; (b) incorporating the probabilistic nature of forced outage into the linear programming optimization is difficult; and (c) the capacity of a generating unit determined by linear programming is a continuous function and must therefore be rounded to the nearest multiple of the capacity of the candidate unit. In systems with large hydroelectric capacity, the forced outage representation is less important, and linear programming may therefore be more suitable.

The discrete nature of generating units can be treated by mixed integer linear programming but, as the number of integer variables increases, there is a severe penalty on the computational cost.

Non-linear programming allows non-linear dependent variables, but its application is limited to special cases.

10.2.2.4. Optimal control

The theory of optimal control is based on the Maximum Principle (Pontryagin), where necessary optimality conditions for the solution of a differentiable non-linear dynamic problem are stated. In this theory, the search for a solution uses only local information (gradients of the total cost criterion with respect to the control variables). Straightforward numerical methods, in common use for many years, are gradient algorithms characterized by iterative algorithms for improving estimates of the control parameters so as to come closer to satisfying the optimality conditions.

It is clear that the necessary optimality conditions are also sufficient *only* if the problem has nice properties such as *convexity* of the cost function to be minimized, *linearity* in the dynamics, etc., which is usually the case in the electric generation expansion problem. The advantage of optimal control is that there is no burden of dimensionality (exponential computing time with respect to the number of state variables). Thus, if the problem under study is continuous in the control variable and convex in the objective function, optimal control can be applied. The National Investment Model (MNI) uses this theory (see Section 10.3.4 and Appendix B).

10.3. REPRESENTATIVE PRODUCTION SIMULATION PROGRAMS AND GENERATING CAPACITY EXPANSION PROGRAMS

This section summarizes several such computer programs. These models are presented as illustrative examples of currently available computer models and is not an endorsement or recommendation of any specific model, or of the usefulness or accuracy of the methods used in a model. It should also be noted that a number of existing models are periodically improved by new features and improvements and that new models are being developed (e.g. Refs [17, 18]).

10.3.1. Wien Automatic System Planning Package (WASP)

The Wien Automatic System Planning Package (WASP) was originally developed in the USA by the Tennessee Valley Authority (TVA) and Oak Ridge

National Laboratory (ORNL) for the IAEA (WASP is further described in Chapter 11). It is the most frequently used and best proven program for electric capacity expansion analyses in the public domain. The most up-to-date version is known as WASP-III.

In the production simulation of WASP, a one-year period is divided into, at most, 12 subperiods, for each of which probabilistic simulation is applied. Equivalent load duration curves in the probabilistic simulation are expanded using Fourier series. The Fourier expansion makes it computationally simple to convolve and deconvolve generating units in the probabilistic simulation.

The decision of the optimum expansion plan is made by forward dynamic programming. The investigator specifies the number of units for each candidate plant type that may be selected each year, in addition to other practical factors that may 'constrain' the solution. If the solution is limited by any such constraints, the input parameters can be adjusted, and the model re-run. The dynamic programming optimization is repeated until the optimum solution (i.e. unconstrained) is found. Previous results are saved, so that additional runs only calculate new alternative configurations of the electric system (Chapter 11 describes WASP-III in detail).

10.3.2. Optimized Generation Planning Program (OGP)

OGP [9, 10, 19] was developed by the General Electric Company, with LOLP as a reliability criterion, using the capacity table method. Production costs are calculated by using predicted average weekday and weekend-day hourly loads.

The most significant difference between OGP and WASP is in the methods used for finding the optimum expansion plan. OGP optimization is performed on a year-to-year basis using the static look-ahead feature. The program evaluates the system reliability for the current year. If additional capacity is required, the program searches among the available generation candidate types. The look-ahead feature compares the different expansion alternatives using surrogate values for costs levelized over the number of years specified by the user, assuming the future load demand stays constant but operation costs escalate.

10.3.3. Electric Generation Expansion Analysis System (EGEAS)

The EGEAS computer model was developed by the Electric Power Research Institute (EPRI). EGEAS can be run in both the expansion optimization and the production simulation modes. Uncertainty analysis, based on automatic sensitivity analysis and data collapsing via description of function estimation, is also available. A complete description of the model can be found in Ref. [20].

10.3.3.1. *Production simulation*

The production simulation option consists of detailed production cost/reliability evaluation for a specified generating system configuration during one or more years. Probabilistic production cost/reliability simulation is performed using a load duration curve based model. Customer load and generating unit availability are modelled as random variables to reflect demand fluctuations and generation forced outages. Two algorithmic implementations are available: an analytic representation of the load duration curve (cumulants) and a piecewise linear numerical representation.

10.3.3.2. *Generating system expansion optimization*

Expansion optimization can be performed with different methodologies, ranging from a simple screening technique to sophisticated non-linear optimization.

(a) *Year end optimization*

This is the simplest of the available options, which allows preliminary screening of planning alternatives overlooking intertemporal cost-benefit interactions and system reliability contributions of the various possible investments. Total costs during the operating life of planning alternatives are discounted and plotted against capacity factor values. The resulting 'screening curves' provide a quick comparison of investment alternatives, allowing dominated alternatives to be identified and excluded from further consideration.

(b) *The Linear Programming (LP) option*

This is an algorithm based on the simplex method. Subject to linear constraints, it selects new capacity that minimizes costs. The constraints cover system reliability, environmental emissions and other resource constraints. The linearity assumption limits the accuracy with which production costs and reliability are modelled. There is no resolution among planning alternative unit sizes. Thermal, limited energy, and storage units may be analysed by the LP option, and the effect of environmental restrictions studied. End effects are captured by an extension period following the planning period. Prescreening of planning alternatives and sensitivity analysis of input variables exhibiting weak interactions with system production costs and reliability may be performed efficiently by the LP option. Unit size, reliability, non-dispatchable generation, inter-ties, subperiod analysis and maintenance scheduling cannot be properly studied with the LP option.

(c) *The Generalized Benders Decomposition Option (GB)*

This is a sophisticated non-linear optimization technique incorporating detailed probabilistic production costing. It is based on an iterative interaction of a simplex algorithm master problem with a probabilistic production costing simulation subproblem. After a sufficient number of iterations, non-linear production costs and reliability relationship are approximated with as small an error bound as desired by the user. It is computationally more efficient than the dynamic programming EGEAS option but produces optimal expansion plans consisting of fractional unit capacity additions. It resolves correctly among planning alternative unit sizes, and it models multiple units correctly in terms of expected energy generated and reliability impacts. System reliability constraints are modelled according to the probabilistic criterion of expected unserved energy. It is suitable for analyses involving thermal, limited energy and storage units, non-dispatchable technology generation, and certain load management activities. A unique capability of the GB option is the estimation of incremental costs to the utility associated with meeting allowed unserved energy reliability targets. This capability replaces reliability constraints by an incremental cost of unserved energy to consumers. Finally, the GB option has not been developed in its present form to model interconnections or subyearly period production costing/reliability considerations. End effects are handled by an extension period model.

(d) *The Dynamic Programming (DP) option*

This is the most sophisticated and robust capacity expansion option in EGEAS and is based on an enumerative method of possible capacity additions and a standard dynamic programming technique for selecting the optimal path over the years of the planning period. Like the GB option, it utilizes detailed probabilistic production simulation. It produces a cost-minimizing expansion plan consisting of whole-unit-planning alternative installations. Whole-unit capacity addition is its main advantage over the GB option. It is suitable for analysis of thermal, limited energy and storage units, non-dispatchable generation and certain types of load management. Computational requirements impose a restriction on the number of planning alternatives analysed simultaneously not to exceed five in each year of the planning period. The DP option is thus more effective for detailed analyses following prescreening performed with the other EGEAS options. In addition to GB option capabilities, the DP option is suitable for incorporating interconnections, subyearly period production costing, and maintenance scheduling. Shortcomings of the DP option compared to the GB option are inability to produce incremental reliability constraint costs and possible inaccuracies in estimating immature availability rates. Finally, the DP option models reliability constraints in terms of reserve margin as well as probabilistic criteria including LOLP and expected unserved energy. End effects are handled in the same way as other options, through an extension period following the planning period.

10.3.3.3. Uncertainties

The handling capabilities of uncertainties in EGEAS include automatic sensitivity analysis and description of function estimation:

(a) *Automatic Sensitivity Analysis (ASA)*

ASA allows easy user specification of uncertain input parameters and assumptions, the range of values they may assume, and jointly varying subsets of uncertain input parameters. The code then proceeds to generate scenarios for each possible combination of uncertain parameter values, updates the database, and runs the specified analysis option for each scenario.

(b) *Describing Function (DF) estimate*

The DF option is a data-collapsing capability available in EGEAS. A polynomial function relating input variation to output variation may be specified by the user. The code builds the functions specified and estimates their parameters using input and output variations from the ASA scenario evaluation. The describing functions thus estimated may be effectively used for trade-off and uncertainty analyses.

10.3.4. National Investment Model (MNI)

The National Investment Model (MNI) was developed by Electricité de France (EDF) to assist in electric system planning (it is described in detail in Appendix B). The basic aim of the MNI is to help in the choice of thermal (conventional and nuclear) generating facilities investments and to draw a picture of the possible trend of the capacity mix of the national electric generating system in the future. Apart from weekly pumping stations, it is not concerned with the choice of hydroelectric plants. The main output of this model is the optimum investment programme, i.e. the schedule of the capacities to be commissioned (or decommissioned) each year for the various types of equipment. The criterion of choice corresponds to the objective set for a quasi-monopolistic establishment (as is EDF) of the public sector: to meet demand at least cost. The purpose is to determine the capital flow which minimizes the global discounted cost of all expenses related to electricity supply (investment, operating, fuel, and failure costs) over a long period of time.

This optimization problem is solved by *optimal control theory* through a 'steepest descent' algorithm (and a process to speed convergence). Thanks to the large number of units of each type in the French electricity system, units may be aggregated into homogeneous groups of plants, which allows a continuous optimization. The model uses an *iterative process* requiring the criterion calculus at each step for all the years concerned (this is done by simulating the matching of production and consumption). In this regard, the MNI starts from an initial investment programme and modifies it until the optimum is reached. The optimization process consists of shuttling back and forth between two main subfunctions. One is in charge of calculating the total cost (which is the economic criterion) for a given configuration of the system. The other has to distort the configuration of the system so that the cost is reduced; the mathematical procedure is an algorithm of gradient (steepest descent algorithm). The new system configuration thus calculated is returned to the initial function up to the moment when a convergence test shows that the proposed programme has reached virtually optimum conditions (as no further worthwhile reduction in costs can be achieved).

10.3.5. Over-Under Model

The Over-Under Model [21] was developed at the Electric Power Research Institute (EPRI). The primary objective of the model is to estimate the levelized consumer cost versus the reserve margin requirement. A unique aspect of the model is the consideration of uncertainty for future demand. Uncertainty of load demand is expressed in the form of probability functions for each future year. By means of user-specified probability for high growth, normal growth and low growth for each year, a probability tree that evolves throughout the study period is developed. Each branch in the tree is a combination of high, normal and low growth through the years of the study period and thus represents a different scenario, each of which is assigned a unique probability. For each growth scenario, the capacity model decides the expansion plan satisfying two criteria: (a) a specified reserve margin is fulfilled, and (b) the plant mix approaches the target plant mix specified as input. However, the expansion planning reflects the contingent nature of expansion planning in that: (i) if demand growth is higher than the past trend, more diesel and gas turbine units are added to the generating system; (ii) if demand growth is lower than the past trend, construction of large units is delayed.

To simulate the production of electricity, two load duration curves are developed for each year: one for the peak season (combining summer and winter), another for the off-peak season (combining spring and autumn). The probabilistic simulation method is applied to each load duration curve. Forced outages of large units are treated probabilistically, whereas small units are treated by the derating approximation to reduce computation requirements. If there is any hydroelectric generation, three levels of hydroelectric power availabilities in each period are assumed, with a certain probability for each level. Thus the probabilistic simulation is repeated three times for each period.

Using the results of the capacity planning and production simulation for each branch of the load growth scenario, the consumer cost is evaluated as the total of the variable costs, fixed costs, outage charges and environmental costs. The outage cost is defined as the total money that consumers as a whole are willing to pay to reduce the outage energy. The environmental cost reflects the total effects of the electricity production on the environment and depends on the plant mix and the amount of production by each type.

Levelized consumer cost is calculated by totalling the weighted cost for each growth scenario, where the assigned probability is used as a weighting factor. The levelized consumer cost calculated is for a specific reserve margin requirement. After the same calculations have been repeated for several different levels of reserve margin requirement, the levelized consumer cost is expressed as a function of reserve margin.

10.3.6. Production Cost Analysis Program (PROCOST)

PROCOST [22] is designed to simulate the operation of an electric generating system consisting of separate regions with inter-tie connections.

Dispatch of generating units in each region is simulated for each bi-hourly period in chronological order. The chronological order of simulation is made possible in conjunction with the Monte Carlo technique to determine the forced outage of thermal units. To determine whether a unit is forced out in each bi-hourly period, a random number is drawn. If the number drawn is less than the forced outage probability of that unit, the unit is determined to be on forced outage during that bi-hourly period. The duration of each occurrence of forced outage is assumed to be two hours for each forced outage. The forced outage effect of both hydro and combustion turbine plants is taken into consideration by reducing the capacity of the units by the forced outage rate (derating method). The maintenance schedule may be automatically simulated or fixed as input.

Once the program decides which units are available in a bi-hourly period, the dispatch simulation is deterministic. The dispatch model loads the run-of-river hydroelectric units and must-run units first. The remaining units are dispatched according to the economic dispatch rule, by means of which the power levels of all the units that are partially loaded are maintained at the same marginal cost of operation.

10.3.7. Production Cost and Reliability System for Electric Utilities (PROMOD-III)

PROMOD-III [23] is a program designed to evaluate production cost and reliability of a utility.

The probabilistic simulation method is adopted to evaluate both reliability and production costs. Calculations for a calendar month are performed with three load periods per week. Unique features of the program include:

- Economic dispatch with transmission penalty;
- Automatic load adjustment representing load management;
- Interruptible load modelling;
- Models simulating characteristics of thermal, nuclear, combined cycle and combustion turbine units;

– Pollution dispatch model;
– Multi-area production simulation.

The financial model produces quarterly and annual income and balance sheets.

10.3.8. Capacity Expansion and Reliability Evaluation System (CERES)

CERES [7] was developed at Ohio State University. The basic principle of the program is similar to that of WASP.

The probabilistic simulation of CERES uses a hybrid of the cumulant method and the piecewise linear approach, which significantly reduces computing time while maintaining reasonable accuracy. The tunnel iteration of dynamic programming is automated and its convergency rate is accelerated by the fathoming technique. It also has an option of applying year-to-year optimization with a static look-ahead period. CERES runs on a time-sharing terminal interactively as well as batch-mode. The financial module of the program allows the user to evaluate the income and balance sheet of the utility based on the optimum or suboptimum expansion plan selected by the dynamic programming optimization.

10.3.9. Production Costs Simulation Program (PCS)

PCS [24] was developed at Ohio State University to analyse production cost of electricity for a period of one year or less. The program uses probabilistic simulation based on a piecewise linear function to expand the equivalent load probability functions. The input load data are given hourly. The hourly load data are then divided into at most 50 groups as specified by the user. This classification may include, for example, night-time of weekends during a season, daytime of weekdays, and weekend days. The program is designed to analyse the effect of technical and regulatory issues such as load control, time-of-day pricing, fuel cost changes, productivity improvements and power storage.

10.3.10. Westinghouse Interactive Generation Planning (WIGPLAN)

The WIGPLAN package [25] consists of seven programs:

(1) Generation database manager
(2) Historical load reduction
(3) Load model
(4) Automatic generation planning
(5) Reliability and maintenance scheduling
(6) Probabilistic production costing
(7) Economic sensitivity.

Operation of generating units is simulated by probabilistic simulation using load duration functions. The automatic generation planning module uses the 'rolling horizon' optimization method [11]. This is a year-to-year optimization using both static and dynamic look-ahead algorithms. By appropriately setting the length of the static and dynamic look-ahead periods for each year, the model can perform any of the following three ways of optimization: (a) year-to-year optimization with static look-ahead, (b) year-to-year optimization with dynamic look-ahead, and (c) global dynamic programming optimization.

10.3.11. SCOPE

SCOPE [26], developed by TVA, is a long-range capacity planning analysis program, using minimal Basic language. It is operated interactively by the user.

The load demand for a year is represented by cumulants for three seasons (winter, summer and spring/autumn). The program presents the capacity and type of each candidate technology that meets the load demand to the user, who then chooses interactively which candidate to evaluate further. The generating costs for all the years are calculated by probabilistic simulation using cumulants. The financial analysis module calculates the annual cost of depreciation, decommissioning cost, interest and annual operating income ratios.

10.3.12. Power System Production Costing Model (POWERSYM)

POWERSYM [27, 28] is TVA's chronological probabilistic production simulation model, which is maintained by Battelle-Columbus as a part of the TEAM-UP project of EPRI. Electric production is simulated in time steps of a year (a week, or an hour). Hourly chronology is maintained, so that chronological constraints such as minimum up and down times, ramp rates, and pumped hydroelectric reservoir constraints are simulated. Forced outages are treated stochastically. Planned outages may be input externally in weekly increments or they may be distributed weekly so as to levelize weekly LOLP.

10.3.13. RELCOMP Model

RELCOMP [29], developed at Argonne National Laboratory, is a production simulation model that uses probabilistic simulation to determine reliabilities and operating costs of an electric utility generating system. Its uses include:

- Analysing in detail expansion plans for a generating system (for example, the expansion plan may have been computed by an optimizing model such as WASP);
- Comparing expansion plans on an equivalent reliability basis, i.e. finding the appropriate amount of totally reliable capacity needed to normalize each system to the same reliability criterion and including a cost factor to account for this capacity and its expected generation;

- Analysing the effects of alternative technologies by simulating them in a generating system (for example, adding coal-fired units with sulphur dioxide scrubbers to an existing generating system);
- Studying the effects on costs and reliability of changes in general characterizations of a generating system, such as maintenance scheduling or forced outage rates.

RELCOMP is oriented toward users who need accurate representations of generating system reliability in addition to production costs. Its strength lies in the level of detail it simulates and reports about the operation of the generating systems.

The simulation is performed in units of time called *periods.* One to 52 periods per year are allowed. The program simulates the system's performance over an entire year or several consecutive years and calculates detailed period-by-period information.

The user must describe the characteristics of the utility generating system, such as individual units in the thermal system, a conglomerate unit with fixed capacity and fixed energy (often hydroelectric units), purchases and sales of power contracted with other utility systems, emergency inter-ties between utilities, and demand on the system. The user can specify the loading order of the thermal system or choose to have it calculated by RELCOMP. The loading order can be based only on economics or can also involve constraints on spinning reserve. Characteristics of the thermal system include:

- Individual units blocked into smaller pieces of capacity (called *blocks*) to simulate generating units that operate at partial capacity;
- Maintenance times, forced outage rates, and costs for individual units;
- Individual heat rates for the blocks.

These data are used to simulate the system. Expected energy generation is computed for each period and for each block not on maintenance. Several reliability indices are calculated by RELCOMP:

- LOLP,
- Mean time between system failures to serve the load (MTBF),
- Frequency of failures to meet the load,
- Average duration of failures to meet the load,
- Unserved energy measured in kW·h,
- Loss of energy probability (LOEP).

The generation costs and their present values are calculated. Present values are most useful when comparing multiyear runs.

The model's detail and accuracy are two of its strong points. Generation (kW·h) and costs are given for each block of each generating unit. Results can be listed period by period for each year. The model provides levels of output that vary from annual summaries of the calculations to period-by-period tables listing

TABLE 10.I. IMPORTANT MODELLING CAPABILITIES OF ICARUS

Identification and evaluation of individual generating units in the context of large systems or electric regions.

Simulation of the effects of single or multiple power plant shutdowns in utility systems or electric regions.

Treatment of operating characteristics for individual units such as:
- Forced outage rates
- Maintenance requirements
- Heat rates
- Fuel types.

Differentiation of costs between units (fuel, fixed and variable O&M, capital).

Inclusion of system load shapes and interconnections.

Recognition of system operating criteria or constraints (e.g. loading priorities, spinning reserves).

Consistent treatment of probabilistic aspects of system operations.

Determination of system reliability criteria (e.g. LOLP, unserved energy).

Ability to distinguish between permanent and temporary shutdowns and timing options.

Rapid evaluation of large systems, long study periods and detailed sensitivity studies for both short- and long-term shutdowns.

the generation of each block. RELCOMP can calculate accurate results within the limits of the specified assumptions and the model's representation of the generating system. However, the user has control of several parameters that trade accuracy for computer time when a high level of accuracy is not critical. The model uses probabilistic simulation to avoid simulating each hour (or shorter interval) of the study. This technique saves computer time at no theoretical sacrifice to the period-by-period results. A separate preprocessor converts hourly load data to a form suitable for RELCOMP.

10.3.14. Investigation of Costs and Reliability in Utility Systems (ICARUS) Model

The ICARUS Model was developed for the US Nuclear Regulatory Commission to evaluate the effects of nuclear unit shutdowns on utility systems while significantly reducing the computational restrictions imposed by conventional methods. An important goal in the development of ICARUS was to preserve an acceptable level of accuracy and the capabilities of conventional methods while reducing the time required to perform calculations. This goal was accomplished by using the basic framework of a conventional production cost model but replacing most of the lengthy convolution calculations with a faster approximation technique.

Table 10.I outlines the capabilities required in the procedure for evaluating the effects of power plant shutdowns. The factors given are important for accurately estimating the impacts of shutdowns and for providing a simulation tool sensitive to key parameters and decision alternatives.

The basic structure for ICARUS is derived from RELCOMP (Section 10.3.13 and Ref. [29]), many components of which have been used directly in ICARUS. The basic framework of RELCOMP provides the required capabilities listed in Table 10.I. The framework is sensitive to data for individual generating unit characteristics, system loads, cost information and inter-ties. It also schedules maintenance, determines dispatch priorities, and performs the basic input and output functions.

The primary area of new development is the determination of energy assignments for individual blocks of generating capacity. Convolutions are still part of the procedure, but they are only used to determine the final energy load duration curve, which represents the combined effects of all loads and outage probabilities. Generation for individual blocks is estimated by a procedure that parallels the convolution process but reduces the number of iterative calculations required. A further description can be found in Ref. [30].

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Chapter 11

THE WASP MODEL FOR ELECTRIC GENERATION EXPANSION ANALYSIS

11.1. INTRODUCTION

The Wien Automatic System Planning Package (WASP) was originally developed by the Tennessee Valley Authority (TVA) and Oak Ridge National Laboratory (ORNL) in the USA to meet the needs of the Market Survey for Nuclear Power in Developing Countries conducted by the IAEA in 1972–1973 [1, 2]. Based on the experience gained in using the program, many improvements were made to the computer code by IAEA staff, leading to the WASP-II version in 1976, which has been widely used by the Agency and Member States [3–7]. Later, the needs of the United Nations Economic Commission for Latin America (ECLA) in a study of the interconnection of the electrical grids of the six Central American countries, where a large potential of hydroelectric resources is available, together with further recommendations given in 1979 by an IAEA Advisory Group on Electric System Expansion Planning, led to a joint ECLA/IAEA effort from June 1978 to November 1980 to develop the WASP-III version [8]. WASP is used by the IAEA, in conjunction with the Model for Analysis of Energy Demand (MAED) (see Chapter 1, Section 2.3.1 (of Chapter 2) and Appendix A) for carrying out energy and nuclear power planning (ENPP) studies for Member States which request them. For this purpose MAED and WASP are executed in tandem to produce optimal electricity generation expansion programmes consistent with the overall energy requirements of the country so as to achieve the economic, social and industrial development objectives.

11.2. ECONOMIC METHODOLOGY AND PARAMETERS USED IN WASP

The purpose of an electric system expansion planning (ESEP) study is to determine the optimal pattern of system expansion to meet the electricity requirements of a country, or a region within the country, over a given period. ESEP studies carried out by the IAEA at the request of a Member State (as part of an ENPP study) place particular emphasis on estimating the possible inclusion of nuclear power in the optimal pattern of expansion. Ideally, the performance of this task would require the estimation and comparison of benefits and costs, both direct and indirect, arising from alternative development patterns in order to determine the power expansion plan which yields maximum total benefits.

Time limitations made a series of simplifying assumptions unavoidable. The methodology used in WASP represents a compromise between practical constraints and theoretical consistency. The main components of the WASP methodology are as follows:

(a) Definition of costs and benefits to be considered and development of methods of estimating their quantitative values;
(b) Selection of criteria for comparing benefit and cost streams extending over time and containing domestic and foreign currency components in variable proportions.

11.2.1. Definition and estimates of costs and benefits

It is assumed that costs rather than net benefits are the only yardstick. This is tantamount to assuming that all programmes of electric power expansion meeting the projected demand with the imposed constraints on reliability offer the same total benefits and that the least-cost programme consequently yields maximum benefits to the ultimate consumers. In the case of electric power, this is a less questionable alternative than it would be in the general case of comparing alternative projects with different outputs. It does, however, ignore such indirect effects as, for instance, (a) different employment levels arising from different power programmes and the consequent effects on savings and investment, and (b) the future value of acquiring a pool of labour skilled in construction, design and operation of nuclear power stations. Further, it can lead to serious distortions where multipurpose hydroelectric plants are involved in the comparisons.

Only costs directly connected with electricity production by a particular type of plant are taken into account. In particular, external or social costs such as those arising from environmental impacts are disregarded in the basic analysis. The imposition of strict environmental control by industrialized countries, leading to higher capital investment and operating costs for thermal power stations, shows that 'external' costs may easily become 'internal' over time. Although it is recognized that the major industrial urban areas of some developing countries may well enact quantitative pollution controls, the effect of this assumption does not appear to be decisive.

In all cases, costs are defined as costs to the economy rather than costs to the electricity producers. A major consequence of this criterion is to eliminate taxes on all types of fuel and equipment from all cost inputs. This is a particularly critical assumption for countries imposing a heavy fiscal burden on some types of fuel, particularly fuel oil. It is felt, however, that the purpose of the study is to determine the total costs of alternative power programmes estimated at the national level. Since the countries concerned are the best judges of their tax policy, which may involve items of social benefits disregarded by the study, and since the electric utilities certainly view taxes on fuel and equipment as elements of costs, alternative computations treating taxes as elements of costs can be carried out for cases which are expected to show critical differences in the results.

11.2.2. Selection of criteria

The aggregation of domestic and foreign currency is carried out on the basis of the official exchange rates prevailing at the time of the study. In many of the countries that might be considered, the official exchange rates do not reflect the relative values that achieve equilibrium between the supply of foreign capital and the demand for it as evidenced by foreign exchange rationing and control, as well as by the existence of parallel markets. Although this approach may substantially underestimate the true value of the ratio of foreign domestic costs, alternative assumptions would have comparable uncertainties.

The aggregation and comparison of time flow of costs is performed by discounting their present worth values using a discount rate which is assumed to remain constant in time. This principle implies two decisions:

(a) *The selection of present worth as a criterion.* This decision must be assessed against its possible alternative, which would be to rank different patterns by their internal rate of return. The latter is clearly ruled out since, apart from its theoretical flaws in the comparison of mutually exclusive projects, it requires estimates of benefits which the study refrains from making.

(b) *The assumption that the rate of discount remains constant in time* may be open to theoretical objections since its value should in principle slowly decrease with higher levels of economic development and larger stocks of capital equipment. The practical difficulties involved in estimating and using variable rates of discount appear, however, to far outweigh the possible advantages.

11.2.3. Method of approach

The steps in a power generating system expansion study using the WASP package are shown schematically in Figs 11.1 and 11.2. Briefly, they are as follows:

WASP input data model

(1) Correlate historical data and future development of energy consumption patterns which might be used to forecast future demand for electricity.

(2) Select a forecast of peak demand to be used as the basis for the study and define the shape of the load duration curve. *Note:* If the ESEP study is part of an ENPP study, steps (1) and (2) are replaced by execution of MAED runs to provide the appropriate information on future requirements for electricity.

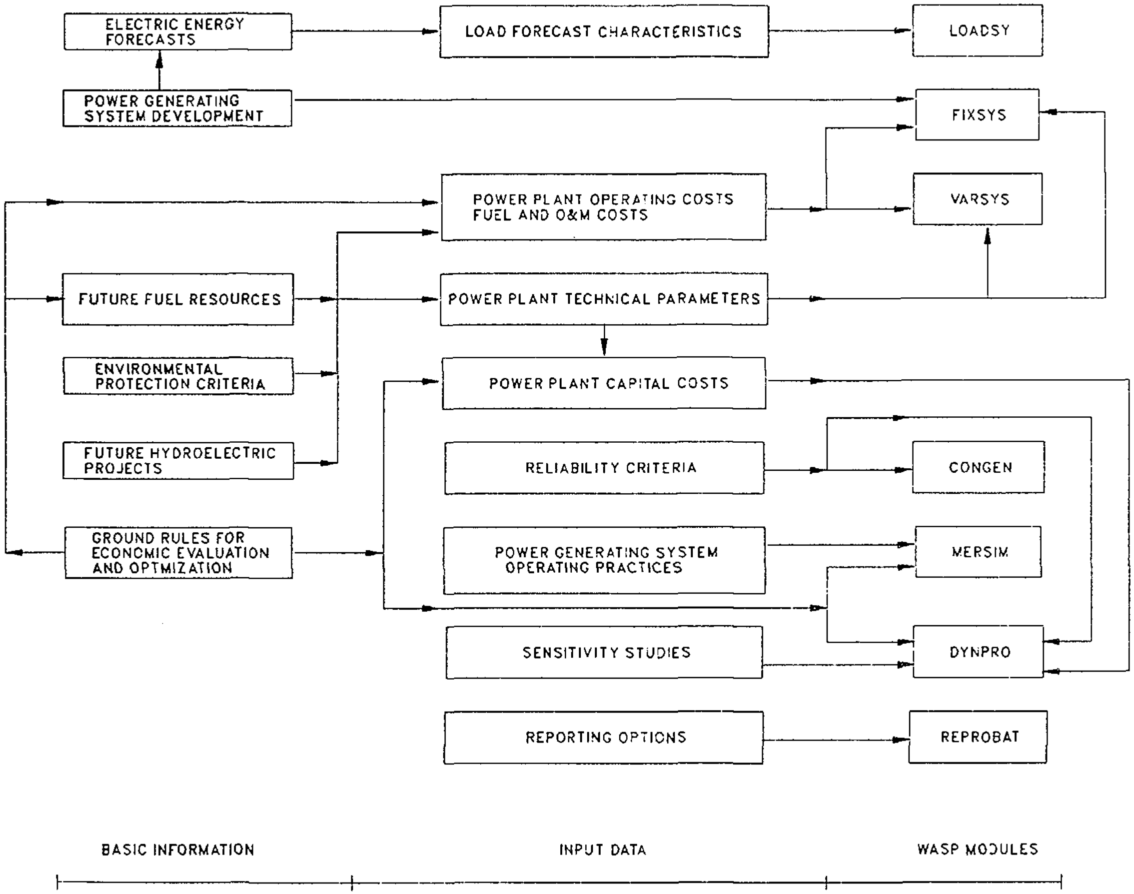


FIG.11.1. WASP input data model.

(3) Define the characteristics of the plants in existence, in construction, or committed for the electric power system being considered.
(4) Define the characteristics of the generating plants which might be considered as expansion alternatives.
(5) Evaluate the role of indigenous sources for electricity generation such as coal, gas and hydro.
(6) Define the economic data and parameters to be used.
(7) Determine, as a function of time, the approximate size of the largest generating unit the system can accept from the standpoint of frequency stability and transmission line.

WASP modules

(8) Determine the tentative optimal (minimum cost) expansion programme.
(9) Determine sensitivity of results to variations in the economic data.
(10) Estimate financing requirements of the selected expansion programme.

WASP output analysis

(11) Analyse transmission system development and estimate related financing requirements.
(12) Check for transmission system and operational constraints.
(13) Check for other constraints, e.g. industrial capabilities, manpower development.

The procedure for a power system expansion planning study using WASP can be summarized as follows. The initial step corresponds to gathering and preparing all input information as required by the various WASP modules as briefly presented in Fig.11.1 and points (1)–(7) of the above list. This is followed by the actual execution of the WASP modules in order to determine the economically optimal expansion plan for the generating system under consideration (point (8)). This tentative 'optimum' is found after an iterative process including sequential execution of some WASP modules and based on user-machine interaction. According to this, at each iteration the user directs the area of study by means of certain constraints on number of units to be added, system reserve, and reliability requirements. The computer programs select, from all strategies of system development permitted, the one that leads to minimum total cost of expansion (best expansion plan). This is reported together with certain information (messages) to tell the user whether the specified constraints acted as a restriction on the solution. The user may then modify the area of study by changing some of the restrictions accordingly, and proceed to a new iteration. The iterative process of adjusting the area of study can be repeated until the solution is free of messages. This solution will be the reference optimum solution for expanding the power generating system and will include the most economical sizes, types and time for addition of new power plants

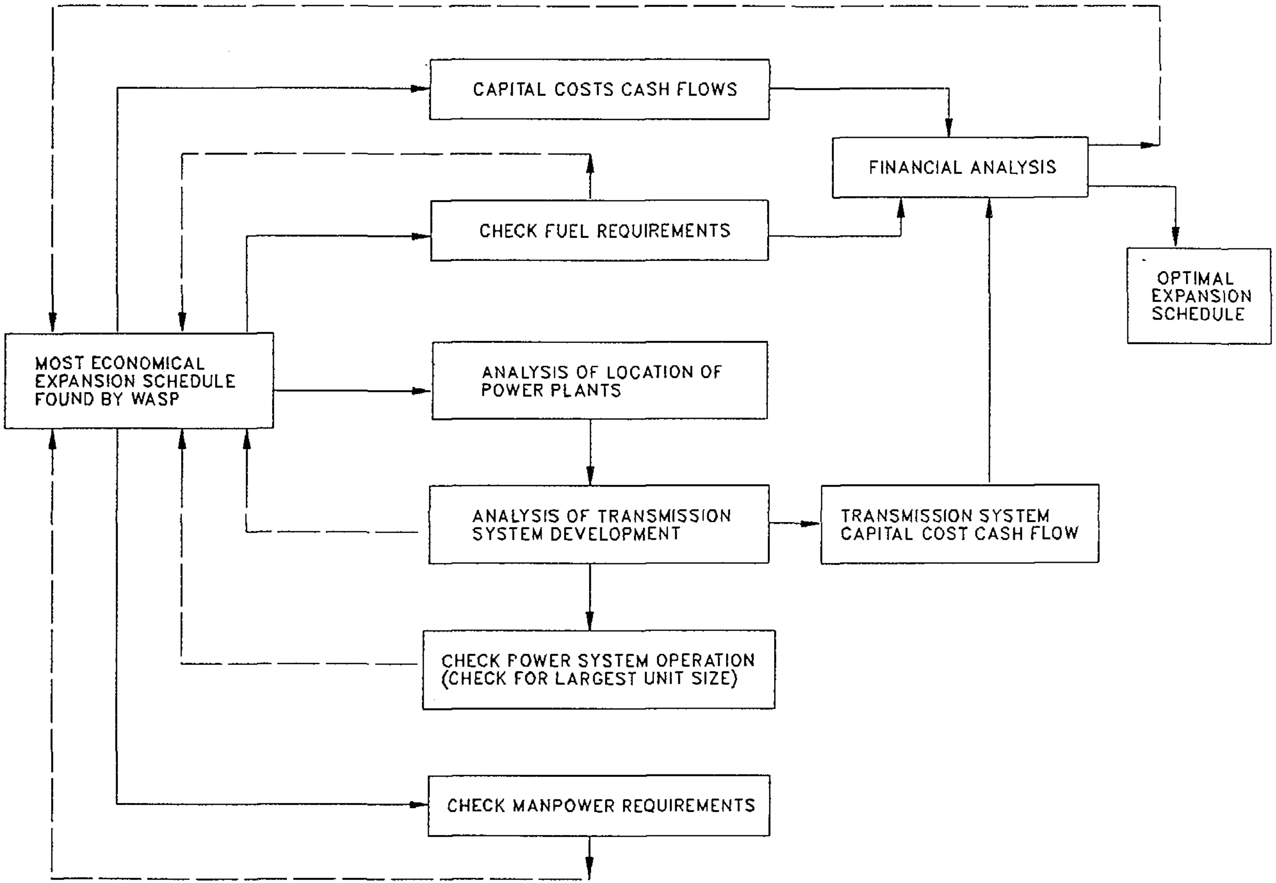


FIG. 11.2. Analysis of WASP output.

into the system. The reference solution is then subject to sensitivity analysis in order to analyse the variations of this solution with changes in the principal economic parameters (point (9)). It is also necessary to determine the total financing requirements imposed by this solution (point (10)).

Once the overall reference solution has been found by WASP, the user must analyse the results and determine whether the proposed expansion schedule of plant additions is also a feasible programme from the standpoint of the system characteristics and the country's economic and financial situation. From the analysis, the planner will check such details as transmission system development (point (11)), frequency stability to determine whether the power system will remain stable after sudden failure of the larger generating units (point (12)), and, finally, any constraints which may be imposed on the expansion programme arising from manpower requirements, industrial capabilities, fuel requirements and financial capabilities of the country to undertake the programme (point (13)).

As a result of these checks, it might be necessary to re-run the WASP program to calculate a new optimal solution which also fulfils the above checks. The procedure is described in Fig.11.2 in a simplified manner.

11.3. OUTLINE OF THE WASP-III MODEL

The WASP-III program permits the economically optimal expansion plan to be found for a power generating system over a period of up to thirty years, within constraints given by the planner. The optimum is evaluated in terms of minimum discounted total costs. WASP-III uses probabilistic estimation of production costs, amount of energy not served, and reliability, together with the dynamic method of optimization for comparing the costs of alternative system expansion policies. A simplified description of the model follows.

Each possible sequence of power units added to the system (expansion plan or expansion policy) meeting the constraints is evaluated by a cost function (the objective function) composed of:

- Capital investment costs (I)
- Salvage value of investment costs (S)
- Fuel costs (F)
- Fuel inventory costs (L)
- Non-fuel operation and maintenance costs (M)
- Cost of the energy not served (O)

Thus,

$$B_j = \sum_{t=1}^{t=T} [\bar{I}_{j,t} - \bar{S}_{j,t} + \bar{F}_{j,t} + \bar{M}_{j,t} + \bar{O}_{j,t}]$$

where B_j is the *objective function* attached to the expansion plan j; t is the time in years (1, 2, ... , T); T is the length of the study period (total number of years). The bar over the symbols has the meaning of discounted values to a reference date at a given discount rate i. The *optimal expansion plan* is defined by Minimum B_j among all j.

If $[K_j]$ is a vector containing the number of all generating units which are in operation in year t for a given expansion plan, then $[K_j]$ must satisfy the following relationship:

$$[K_j] = [K_{t-1}] + [A_t] - [R_t] + [U_t]$$

where $[A_t]$ is the vector of committed additions of units in year t; $[R_t]$ is the vector of committed retirements of units in year t; $[U_t]$ is the vector of candidate generating units added to the system in year t, such as $[U_t] \geqslant [0]$.

$[A_t]$ and $[R_t]$ are given data, and $[U_t]$ is the unknown variable to be determined; the latter is called the system configuration vector or, simply, the *system configuration.*

WASP-III permits the year to be subdivided into an equal number of periods in order to better represent the seasonal variations of the load and the hydroelectric plant characteristics, as well as for more accurate treatment of the maintenance requirements of thermal plants. Defining the critical period (p) as the period of the year for which the difference between the corresponding available generating capacity and the peak demand has the smallest value, if $P(K_{t,p})$ is the installed capacity of the system in the critical period, the following constraints should be met by every acceptable configuration:

$$(1 + a_t)D_{t,p} \leqslant P(K_{t,p}) \leqslant (1 + b_t)D_{t,p}$$

which simply states that the installed capacity in the critical period must lie between the given minimum and maximum reserve margins a_t and b_t above the peak demand $D_{t,p}$ in the critical period of the year.

The reliability of the system configuration is evaluated by WASP in terms of the loss of load probability (LOLP) index. This index is calculated by the program for each period and each hydrocondition of the year; from these values it determines the average annual LOLP as the sum of the LOLPs for the period, which in turn are calculated as the sum of the LOLPs for each hydrocondition (in the same period), weighted by the hydrocondition probabilities.

If $LOLP(K_{t,a})$ and $LOLP(K_{t,p})$ are, respectively, the annual and period's LOLPs, every acceptable configuration must respect the following constraints:

$$LOLP(K_{t,a}) \leqslant C_{t,a}$$

$$\mathrm{LOLP}(K_{t,p}) \leqslant C_{t,p} \quad \text{(for all periods)}$$

where $C_{t,a}$ and $C_{t,p}$ are input data specified by the user.

If an expansion programme contains system configurations for which the annual energy demand E_t is greater than the expected annual generation G_t of all units existing in the configuration for the corresponding year t, the total costs of the programme should be penalized by the resulting cost of the energy not served. This cost is a function of the amount of energy not served, N_t, which is calculated as:

$$N_t = E_t - G_t$$

The user may also impose 'tunnel' constraints on the configuration vector $[U_t]$ so that every acceptable configuration must respect:

$$[U_t^0] \leqslant [U_t] \leqslant [U_t^0] + [\Delta U_t]$$

where $[U_t^0]$ is the smallest value permitted to the configuration vector $[U_t]$ and $[\Delta U_t]$ is the tunnel constraint or tunnel width.

The problem as stated here corresponds to finding the values of vector $[U_t]$ over the period of study which satisfy the above expressions. This will be the 'best' system expansion programme within the constraints given by the user. The WASP code finds this best expansion plan by using the dynamic programming technique. In doing this, the program also detects whether the solution has hit the tunnel boundaries of vector $[U_t]$ and gives a message in its output. Consequently, the user should proceed to new iterations, relaxing the constraints as indicated by the WASP output, until a solution free of messages is found. This will be the 'optimum expansion plan' for the system under consideration, as explained in Section 11.2.3 above.

11.3.1. Calculation of costs

The various cost components in expression B_j are calculated in WASP with certain models, in order to account for:

(a) Characteristics of the electric *load forecast,*
(b) Characteristics of *thermal and nuclear plants,*
(c) Characteristics of *hydroelectric plants,*
(d) Stochastic nature of hydrology *(hydrological conditions),*
(e) Cost of the *energy not served.*

In the above list and throughout this description, the word *plant* is used when referring to a combination of one or more generating *units* (for thermal) and one or more *projects* (for hydroelectric).

The *load* is modelled by the peak load and the energy demand for each period (up to 12) in each year (up to 30), and their corresponding inverted load duration curves. The latter represent the probability that the load will equal or exceed a value taken at random in the period. (For computational convenience, the inverted load duration curves are expanded in Fourier series by the computer program.)

The models for nuclear and thermal plants are each described by:

- Maximum and minimum generating capacities,
- Heat rate at minimum capacity and incremental heat rate between minimum and maximum capacities,
- Maintenance requirements (scheduled outages),
- Failure probability (forced outage rate),
- Capital investment costs (for expansion candidates),
- Variable fuel cost,
- Fuel inventory cost (for expansion candidates),
- Fixed component and variable component of (non-fuel) operating and maintenance (O&M) costs,
- Plant life (for expansion candidates).

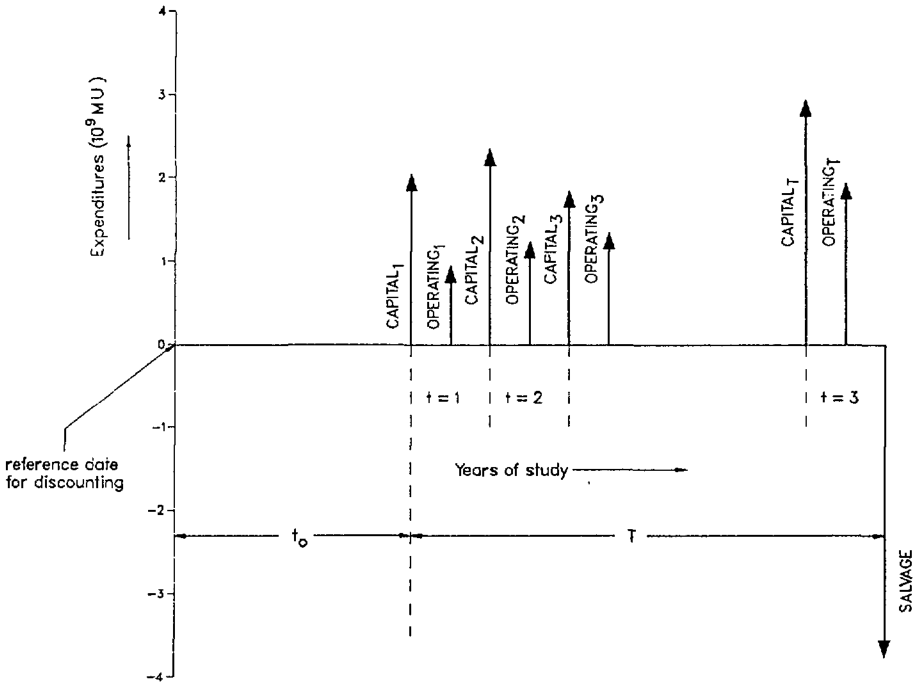
The models for hydroelectric projects are for run-of-river, daily peaking, weekly peaking and seasonal storage regulating cycle. They are defined (identifying for each project) by:

- Minimum and maximum capacities,
- Energy storage capacity of the reservoirs,
- Energy available per period,
- Capital investment costs (for projects used as expansion candidates),
- Fixed O&M costs,
- Plant life (for projects used as expansion candidates).

The hydroelectric plants are assumed to be 100% reliable and have no associated cost for water.

The stochastic nature of the hydrology is treated by means of hydrological conditions (up to five) or equivalent years of rainfall (e.g. dry year, average year, wet year). Each hydrological condition is defined by its probability of occurrence, α, which is determined from statistical information applicable to the whole hydroelectric system. For each hydrocondition, the user must specify the capacity and energy available from each hydroelectric project.

The cost of energy not served reflects the expected damages to the economy of the country or region under study when a certain amount of electrical energy is not supplied. In WASP this cost is modelled through a quadratic function which relates the incremental unit cost of the energy not served to the amount of energy not supplied. *The cost of the energy not served permits an automatic definition of the adequate amount of reserve capacity in the power system.*



$$B_j = (\sum \text{CAPITAL}_t + \text{OPERATING}_t) - \text{SALVAGE}$$

where:

B_j:	Objective function (total cost) for the expansion plan
CAPITAL_t:	Sum of investment costs for the various units added in year t of the study
OPERATING_t:	Sum of all system operating costs (fuel, operation and maintenance and energy not served) in year t of the study
SALVAGE:	Sum of salvage values at horizon of the investments for all units added by the expansion plan over the study period
t_o:	Number of years between the reference date for discounting and the first year of the study
T :	Length of the study period (in number of years)
$\sum$:	Cumulated sum over the years, from t=1 to t=T

FIG.11.3. Schematic diagram of cash flow of expenditure for one expansion plan using the WASP-III program (MU: monetary unit).

To calculate the present worth values of the cost components of expression B_j, the present worth factors used are evaluated assuming that the full capital investment for a plant added by the expansion plan is made at the beginning of the year in which it goes into service and also that its salvage value is the credit at the horizon for the remaining economic life of the plant. Fuel inventory costs are treated as investment costs, but full credit is taken at the horizon (i.e. these costs are not depreciated). All the other costs (fuel, O&M and energy not served) are assumed to occur in the middle of the respective year. These assumptions are illustrated in Fig.11.3.

According to this, the cost components of expression B_j are calculated as follows:

(a) Capital investment cost and salvage value

$$\bar{I}_{j,t} = (1+i)^{-t'} \Sigma \, [UI_k MW_k]$$

$$\bar{S}_{j,t} = (1+i)^{-T'} \Sigma [\delta_{k,t} \, UI_k MW_k]$$

where:

- Σ is the sum calculated considering all (thermal or hydro) units k added in year t by the expansion plan j,
- UI_k is the capital investment cost of unit k, expressed in monetary units per MW,
- MW_k is the capacity of unit k expressed in MW,
- $\delta_{k,t}$ is the salvage value factor at the horizon for unit k,
- i is the discount rate,
- $t' = t + t_0 - 1$
- $T' = T + t_0$

and t, t_0 and T are as defined in Fig.11.3.

(b) Fuel costs

$$\bar{F}_{j,t} = (1+i)^{-t'-0.5} \sum_{h=1}^{h=NHYD} [\alpha_h \psi_{j,t,h}]$$

where α_h is the probability of the hydrocondition h; $\psi_{j,t,h}$ is the total fuel cost (sum of fuel costs for thermal and nuclear units) for each hydrocondition; and NHYD represents the total number of hydroconditions defined in the study.

The energy generated by each unit in the system is calculated by probabilistic simulation. In this approach, the forced outages of thermal units are convolved with the inverted load duration curve and, consequently, the effect of unexpected outages of thermal units upon other units is accounted for probabilistically. The net effect is an increase in the generation of peaking units in order to make up the reduction of base units generated owing to scheduled outages for maintenance and unit failures, thus increasing the expected generating costs of the system. Obviously, the fuel cost of a particular block of energy generated by a given unit is calculated as the amount of generation times the unit fuel cost times the unit heat rate.

(c) Fuel inventory cost

$$\bar{L}_{j,t} = [(1+i)^{-t'} - (1+i)^{-T'}]\, \Sigma[\mathrm{UFIC}_{kt,t}\, \mathrm{MW}_{kt,t}]$$

where the indicated sum Σ is calculated over all thermal units (kt) added to the system in year t, and $\mathrm{UFIC}_{kt,t}$ is the unitary fuel inventory cost of unit kt (in monetary units per MW).

(d) O&M costs

$$\bar{M}_{j,t} = (1+i)^{-t'-0.5}\, \Sigma[\mathrm{UFO\&M}_{\ell}\, \mathrm{MW}_{\ell} + \mathrm{UVO\&M}_{\ell} G_{\ell,t}]$$

where:

Σ	is the sum over all units, ℓ, existing in the system in year t,
$\mathrm{UFO\&M}_{\ell}$	is the unitary fixed O&M cost of unit ℓ, expressed in monetary units per MW·a,
$\mathrm{UVO\&M}_{\ell}$	is the unitary variable O&M cost of unit ℓ, expressed in monetary units per kW·h, and
$G_{\ell,t}$	is the expected generation of unit ℓ in year t, in kW·h.

The expected generation of a unit is calculated as the sum of the energy generated by the unit in each hydrocondition weighted by the probabilities of the hydroconditions.

(e) Energy-not-served cost

$$\bar{O}_{j,t} = (1+i)^{-t-0.5} \sum_{h=1}^{h=\mathrm{NHYD}} \left\{ \frac{c}{3}\left(\frac{N_{t,h}}{EA_t}\right)^2 + \frac{b}{2}\left(\frac{N_{t,h}}{EA_t}\right) + a \right\} N_{t,h}\, \alpha_h$$

where:

a, b, c are constants ($/kW·h) given as input data,

$N_{t,h}$ is the amount of energy not served (kW·h) for hydrocondition h in the year t, and

EA_t is the total energy demand (kW·h) of the system in year t.

The cost components of the objective function (expression B_j) are all presented in expressions from (a) through (e) in a simplified form. In fact, all these expressions have been derived assuming each expansion candidate plant to be composed of one single unit (hydroelectric, thermal or nuclear), whereas in the WASP-III program the expansion candidates are defined as plants, and the number of units (or projects) from each plant to be added each year is to be determined by the WASP study. In addition, the WASP-III program:

- combines capital investment cost and the corresponding salvage value with the fuel inventory cost and its salvage value;
- aggregates operating costs by types of (fuel) plant;
- separates all expenditure (capital or operating) into local and foreign components;
- permits escalation of all costs as the study progresses;
- has provisions to apply different discount rates and escalation ratios for each year for the local and foreign cost components, and for the various types of plants defined for the case under consideration, and to change the constants (a, b and c) of the expression for evaluating the energy-not-served cost from year to year.

Table 11.I lists the most important capabilities of the WASP-III computer code.

11.3.2. The WASP-III modules

Figure 11.4 is a simplified flow chart of the WASP-III model illustrating the flow of information from the various WASP modules and associated data files. The numbering of the first three modules is arbitrary, since they can be executed independently of each other in any order. For convenience, however, these modules have been numbered 1, 2 and 3. On the other hand, modules 4, 5 and 6 must be executed in order, after execution of modules 1, 2 and 3. There is also a seventh module, REPROBAT, which produces a summary report of the first six modules.

Module 1, LOADSY (Load System Description), processes information describing period peak loads and load duration curves for the power system over the study period.

Module 2, FIXSYS (Fixed System Description), processes information describing the existing generating system and any predetermined additions or retirements.

TABLE 11.I. PRINCIPAL CAPABILITIES OF THE WASP-III PROGRAM

30 years of study period.

12 periods (seasons) per year.

360 load duration curves (one for each period and for each year).

100 cosine terms in the Fourier representation of the inverted load duration curve of each period.

7 types of plants grouped by 'fuel' types, composed of:
- 5 types of thermal plants
- 2 composite hydroelectric plants.

58 thermal plants of multiple units. This limit corresponds to the total number of plants in the fixed system plus those thermal plants considered for system expansion which are described in the variable system.

14 types of candidate plants for system expansion, composed of:
- 12 types of thermal plants
- 2 hydroelectric plant types, each composed of up to 30 projects.

5 hydrological conditions (hydrological years).

300 configurations of the system in any given year (in one single iteration involving sequential runs of modules 4 to 6).

3000 system configurations in all the study period (in one single iteration involving sequential runs of modules 4 to 6).

60 (2 × 30)	discount rates on capital investment costs (one for domestic and one for foreign capital costs each year).
60 (2 × 30)	discount rates on operating costs (one for domestic and one for foreign capital costs of each expansion candidate).
840 (2 × 14 × 30)	escalation ratios on capital investment costs per year (one for domestic and one for foreign capital investment costs of each expansion candidate).
480 (2 × 8 × 30)	escalation ratios on operating costs per year (one for domestic and one for foreign operating costs of each 'fuel' type (7) and for the cost of energy not served).

Module 3, VARSYS (Variable System Description), processes information describing the various generating plants which are to be considered as candidates for expanding the generation system.

Module 4, CONGEN (Configuration Generator), calculates all possible year-to-year combinations of expansion candidate additions which satisfy certain input constraints and which, in combination with the fixed system, can satisfy the projected loads.

Module 5, MERSIM (Merge and Simulate), considers all configurations put forward by CONGEN and uses probabilistic simulation of system operation to calculate the associated production costs, energy not served, and system reliability for each configuration. The module also calculates plant loading orders if desired and makes use of all previously simulated configurations.

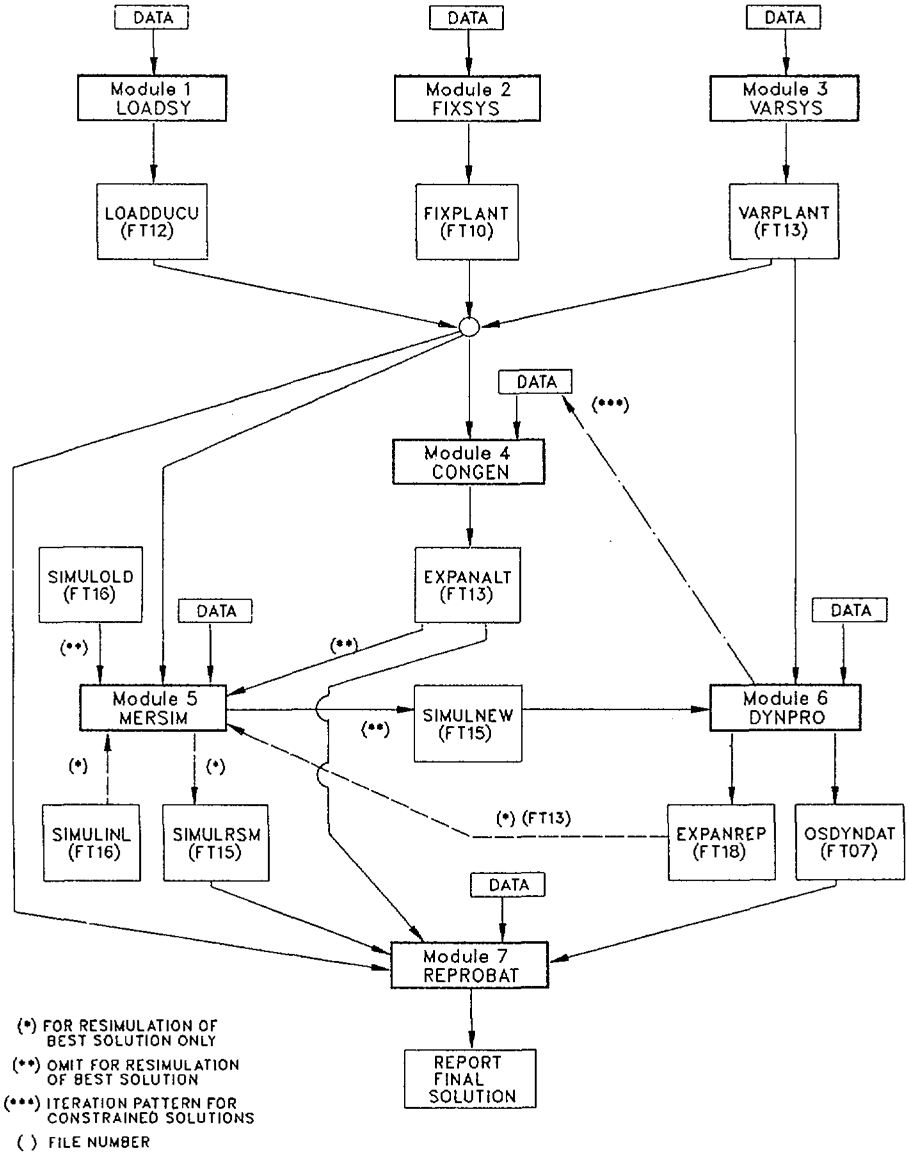


FIG. 11.4. Simplified flow chart of the WASP-III computer model.

Module 6, DYNPRO (Dynamic Programming Optimization), determines the optimum expansion plan based on previously derived operating costs along with input information on capital costs, energy-not-served cost, economic parameters, and reliability criteria.

Module 7, REPROBAT (Report Writer of WASP in a Batched Environment), writes a report summarizing the total or partial results for the optimum or near optimum power system expansion plan and for fixed expansion schedules.

11.3.3. File handling

WASP uses magnetic disc files to pass information from one module to another and to save information from one simulation to another, thus avoiding waste of computer time on repetition of calculations previously done. These files are created and identified as follows:

LOADSY creates a file, LOADDUCU, which is used subsequently by CONGEN, MERSIM and REPROBAT.

FIXSYS creates a file, FIXPLANT, which is used subsequently by CONGEN, MERSIM and REPROBAT.

VARSYS creates a file, VARPLANT, used by CONGEN, MERSIM, DYNPRO and REPROBAT.

CONGEN creates a file, EXPANALT, also used by CONGEN, MERSIM, DYNPRO and REPROBAT, and uses a scratch file as a temporary work file.

MERSIM simulates system operation for any configuration not already listed on the SIMULOLD file created by the previous MERSIM run (if any) and merges the new results with the old ones to produce a SIMULNEW file containing: annual operating costs, amount of energy not served, and LOLP for all configurations simulated to date. This SIMULNEW file is used by DYNPRO as input as well as by the next MERSIM run after it has been renamed SIMULOLD. A SIMULINL file is created as a 'null' file to be used in place of SIMULOLD for the first MERSIM run of a case study. A SIMULRSM file is used in place of SIMULNEW when using MERSIM to get a detailed resimulation of the optimal solution produced by DYNPRO. Furthermore, the creation of a SIMULREC file is recommended for use in recovering the results of an incomplete MERSIM run and for enlarging the simulation files.

DYNPRO considers all configurations currently on the EXPANALT file and the respective operating costs, energy not served, and reliability on the SIMULNEW file, together with information on the VARPLANT file. DYNPRO has provisions for creating two output files for use by other WASP modules, files EXPANREP and OSDYNDAT. EXPANREP is the equivalent of EXPANALT except that it contains only the configurations of the optimal solution; it is used instead of EXPANALT in a MERSIM run after DYNPRO to get a detailed simulation output for the optimal solution. OSDYNDAT is used as input file by REPROBAT.

REPROBAT does not create a file but uses the files from the other six WASP modules to write a report summarizing the results for the optimal solution. It also uses three scratch files as temporary work files.

11.3.4. Computer time requirements

The modular structure of the WASP-III package permits the user to monitor intermediate results, avoiding the waste of large amounts of computer time owing to input data errors. The ability of the simulating module (MERSIM) to save and make use of information on previously simulated configurations is also an important feature of the program aimed at reducing the total computer time needed to execute a WASP study.

The computer time requirements for carrying out a generation planning study using WASP-III depend on:

(a) The complexity of the system under consideration,
(b) The number of hydrological conditions defined,
(c) The number of periods into which the year is divided,
(d) The total number of years considered,
(e) The accuracy required for simulating the system operation,
(f) The total number of configurations generated during the study.

Simulation of a 16 year fixed expansion plan with four periods per year, three hydroconditions and 20 Fourier coefficients takes about 16 seconds of CPU time in the IAEA's IBM 3032 computer. The full dynamic programming study carried out for the sample problem used to document the WASP-III User's Manual, and involving simulation of about 3600 configurations in total, took as much as 100 minutes of CPU time on the same computer.

11.4. CONCEPTUAL DIFFERENCES BETWEEN WASP-II AND WASP-III

The most important conceptual differences between WASP-II and WASP-III are summarized in Table 11.II and described below.

11.4.1. Energy-not-served cost

It is now generally recognized by electric power system planners that the analysis and economic optimization of expansion planning should include not only the impact of capital investment, fuel and O&M costs, but also the cost of the expected energy not served. The use of the LOLP criterion based on available installed capacity alone does not give assurance that the energy supply will not fail to meet the energy demand by a large amount; this is apparent when

TABLE 11.II. MOST IMPORTANT CONCEPTUAL DIFFERENCES BETWEEN WASP-II AND WASP-III

Concept	WASP-II model	WASP-III model
ENS[a] cost	No	Yes
Type of hydroelectric plants	Run-of-river Peaking Emergency	Run-of-river Daily regulating cycle Weekly regulating cycle Seasonal regulating cycle
Provides more information about hydroelectric project operation	No	Yes
Number of series of competing hydroelectric projects	One series (20 projects)	Two series (30 projects each)
Probabilistic simulation of power plant 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 in the case of shortage in hydroelectric energy	Incorrect	Correct
Pumped storage plant	Yes	No
Input data for hydroelectric projects	Complex	Simplified
Input data on load duration curves	Fifth-order polynomial description	Fifth-order polynomial or point-by-point description
Reports and printout formats	Normal	Highly improved

[a] ENS: energy not served.

the power generating system contains energy-limited plants. Such is the case for hydroelectric plants operating during years of dry hydrological conditions.

WASP-III has the energy-not-served cost in the objective function to be optimized whereas WASP-II does not consider it. In WASP-III the incremental cost of unsupplied energy is related to the energy not served through a second-order polynomial whose coefficients are specified by the user. The user is thus involved in the problem of finding the right relation between energy not served and its cost.

11.4.2. Type and parameters of hydroelectric plants

The WASP-II model handles run-of-river, peaking and emergency hydroelectric plants; WASP-III handles run-of-river and peaking hydroelectric plants but the latter can be individualized either as daily, weekly or seasonal regulating projects. The operating cycle and associated parameters of peaking hydroelectric projects are calculated by the subroutine HYRUN of FIXSYS and VARSYS modules of WASP-III based on data input specified by the user and certain assumptions for the different modes of operation made in the program. Definition of emergency hydroelectric plants is no longer necessary in WASP-III since the emergency hydroelectric generation cost is intrinsically evaluated in the energy-not-served cost function.

11.4.3. Series of competing hydroelectric projects

Perhaps one of the most powerful optimization features of WASP-III is its ability to allow for competition among two series of hydroelectric projects (maximum 30 projects each) and up to 12 thermal candidate plants (maximum 50 units each). The sequence in which the hydroelectric projects can be taken in each series is given by the user; the computer program cannot change this sequence but it optimizes the timing of project installation in both series of hydroelectric projects. The WASP-II permits consideration of only one series of hydroelectric projects (maximum 20) and no competition among them is possible.

11.4.4. Calculation of energy not served and LOLP

In those cases where the hydroelectric composite plants do not have enough energy to satisfy the minimum generation requirements of these plants, their respective capacity is derated to a value small enough to fulfil that condition. In such a case, the decrease in total available capacity in the generating system will give larger (and correct) values of LOLP and the amount of energy not served. WASP-III considers this correction when this situation arises whereas WASP-II does not and, consequently, calculates an erroneously better reliability for the power system.

11.4.5. Probabilistic simulation of power plant operation

WASP-III performs the calculation of the expected generation of each power plant by means of probabilistic simulation. In this process, the correct position of the hydroelectric composite plants in the loading order is extremely important. WASP-III merges the hydroelectric projects into four composite hydroelectric plants: two run-of-river composite plants (the handling of which is trivial since they are simply placed in the base portion of the load duration curve) and two peaking hydroelectric composite plants. The exact treatment of probabilistic simulation with two peaking hydroelectric plants becomes fairly complex and was one of the major efforts undertaken by the Agency in the development of the WASP-III program.

To keep the algorithm within reasonable limits of complexity, the simulation of pumped storage plants was not included in the WASP-III model (WASP-II permits simulation of these plants); it is, however, planned to treat it together with other storage technologies for electricity generation in the next development foreseen for WASP.

11.4.6. Input data, reports and printouts

The input data required to describe hydroelectric projects have been simplified in WASP-III; the user inputs all information expressed in physical units (MW and GW·h) and not in relative units (factors) as required by WASP-II. The reports of all WASP-III modules have better layouts, contain more information useful to the user and are easier to read. In addition, the input data on load duration curves in WASP-III can be made using a fifth-order polynomial or a point-by-point description; the latter option is most valuable since it gives a better fitting of the Fourier expansion of the load duration curve. WASP-II only permits the fifth-order polynomial representation.

11.5. TRAINING IN THE USE OF THE WASP PROGRAM

In the period Jan. 1975 to June 1983, 163 senior engineers and power system planners from 50 countries and three international organizations were trained by the IAEA in the use of the various versions of WASP. The major training effort was made at Argonne National Laboratory (ANL), USA, in the Training Course on Electric System Expansion Planning sponsored by the IAEA and the US Department of Energy, which was given five times between Jan. 1978 and June 1983. Some countries which had already sent specialists to Vienna for IAEA training on WASP between Jan. 1975 and Dec. 1977 also sent participants to the ANL courses. Consequently, 49 participants from 20 countries and three international organizations received training in Vienna, and 114 participants from 43 countries attended the courses on Electric System Expansion Planning at Argonne National Laboratory. Altogether, the trainees performed about 70 power generating system expansion studies using the various versions of WASP available to them.

11.6. RELEASE OF THE WASP PROGRAM

WASP has been released to IAEA Member States with 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 using WASP in 53 studies and planning at least 30 future WASP studies. Five international organizations (the UN Economic Commission for Latin America (ECLA), the UN Economic and Social Commission for Asia and the Pacific (ESCAP), the International Bank for Reconstruction and Development (IBRD), Comisión de Integración Eléctrica Regional (CIER), and the Inter-American Development Bank (IADB)) are recipients of both versions of WASP. ESCAP and ECLA reported to the IAEA 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 from IAEA Member States.

The IAEA is prepared to release WASP and to provide the necessary technical assistance to implement the package in the recipient country.

11.7. FURTHER DEVELOPMENT OF WASP AT THE IAEA

Depending on the availability of manpower and funds, future improvements of WASP-III are considered: (a) in the MERSIM module to introduce a dynamic programming subroutine for optimizing the operation of hydroelectric power plants supported by large water reservoirs, and (b) to include the representation of pumped storage plants and other storage technologies.

11.8. LIMITATIONS OF THE WASP PROGRAM

The main limitations of the WASP program are in its application to power generating systems with a very large component of hydroelectric power, particularly if some hydroelectric projects can provide interannual regulation (i.e. energy can be transferred from one year to another), and the order of economic merit for adding hydroelectric projects has not been previously determined.

The WASP code may also produce an inaccurate representation of the system operation for power systems relatively small and composed of a small number of thermal units only.

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Appendix A

THE MAED MODEL

A.1. INTRODUCTION

The Model of Analysis of the Energy Demand (MAED) is a simulation model designed to evaluate medium- and long-term demand for energy in a country (or a region). The model is based on methodology similar to that developed by B.Chateau and B. Lapillone of l'Institut économique et juridique, Université de Grenoble, France, for the MEDEE model [1]. The MAED model is, in fact, very similar to the simplified MEDEE-2 [2, 3], which was adapted by B. Lapillone to suit the needs of the International Institute for Applied Systems Analysis (IIASA), Laxenburg, Austria.

The MAED methodology comprises the following basic sequence of operations:

(1) Breaking down the structure of the country's final energy consumption in a consistent manner,
(2) Identifying the social, economic and technical factors influencing each category of final energy demand,
(3) Specifying (in mathematical terms) the functional links between energy consumption and the factors governing that consumption,
(4) Constructing scenarios of socio-economic and technical development,
(5) Evaluating the energy consumption corresponding to each scenario.

The energy demand from final consumers is, as far as possible, always evaluated in terms of useful energy, i.e. of service rendered, and not only in terms of the amount of energy supplied. This differentiation between energy expressed in useful terms and final terms facilitates the study of the interchangeability of various energy forms and assists the assessment of the technical improvements in the appliances used by final consumers.

Although the general structure of the MEDEE-2 model has been retained, the changes introduced in the MAED model have consisted mainly of amendments to the number of exogenously defined parameters, the method of calculating the energy demand from certain sectors and the presentation of the results. MAED also includes additional modules to convert annual electricity demand to hourly consumption, i.e. to the demand on the grid. In that way, the MAED results can be fed into the WASP model (see Chapter 11), which is used to study the optimization of the electricity generating sector.

The MAED model has been applied for the first time in a study carried out in co-operation between the Société nationale d'électricité et du gaz (SONELGAZ) of Algeria and the IAEA [4] (and see Section 2.3.1).

The MAED model is designed to reflect:

(a) Structural changes affecting medium- and long-term energy demand by means of a detailed analysis of the social, economic and technical system. This approach takes into account, in particular, the changing social needs of the individual, including heating, equipment, transport, etc., according to the area in which the individual lives (town, country), the industrial policy of the country (more or less rapid development of various types of industry), policy with regard to transport and other matters, as well as technological progress.

(b) Trends in the potential market for each final energy form: electricity, coal, gas, oil, solar energy, etc.

The interchangeability between energy forms is not calculated automatically from the trends in prices for each energy form and from the coefficients of elasticity but from the analysis carried out when the scenarios are constructed. This may be seen as a disadvantage of the model, but it must be remembered that, in the present economic situation, where prices are continually changing, economists have no technique for predicting the impact of price trends on demand. As is demonstrated by the considerable discrepancies between the results of many studies concerning price elasticity, the traditional method of dealing with elasticity is no longer satisfactory. Elasticity used to be calculated on the basis of past experience, i.e. of times when energy prices were stable or tended to diminish, and they therefore no longer apply to the present energy situation.

For these various reasons, the MAED model does not calculate trends in energy demand from the direct trends in prices; for instance, the demand for petrol is not deduced from a hypothetical petrol price. The price is simply reflected implicitly in the construction of the scenario, serving as a back-drop to modulate future trends in data on the number of cars per inhabitant or the number of kilometres covered each year by car. In this case, the model calculates the demand for motor fuels solely as a function of the socio-economic parameters: the number of cars, average distance covered, etc.

A general description of the MAED model in its MAED-1 version [5], as currently used by the IAEA, is given in the next section.

A.2. DESCRIPTION OF THE MODEL

The general structure of the MAED model is shown schematically in Fig. A.1.

Module 1 (energy demand) calculates the final energy demand per energy form and per economic sector for each reference year according to the various parameters describing each socio-economic and technical development scenario.

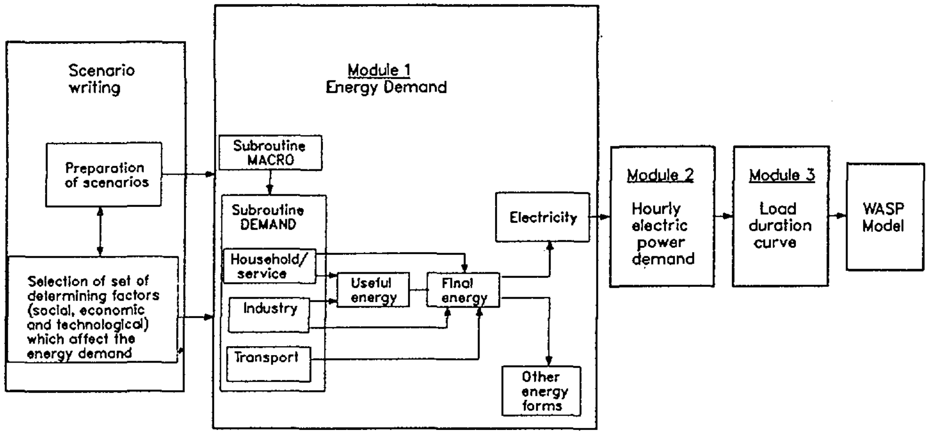

FIG.A.1. Interconnection between the MAED and WASP methodologies for energy/nuclear power planning studies.

Module 2 (hourly electric power demand) converts the annual demand for electricity in each sector to the hourly demand, i.e. the hourly demand imposed on the grid by the respective sector.

Module 3 (load duration curve) ranks the hourly demands imposed on the grid in decreasing order of magnitude and provides what electrical engineers call the load duration curve. This curve forms a basic input to the optimization study of the electricity generating sector using the WASP model.

Module 4 (load modulation coefficients), not shown in Fig.A.1, is an auxiliary module which may be used to analyse the past evolution of the coefficients describing the variation of the hourly electric loads, based on load curve information determined from statistical data.

Module 1 forms an essential part of the MAED model because it determines the annual demand for energy in all its forms, and it is therefore described in detail below.

A.2.1. Module 1: energy demand

In the MAED model, the energy demand is calculated according to a scenario which may itself be subdivided into two subscenarios. One is linked to the socio-economic system and describes the fundamental characteristics of the social and economic development of the country. The other relates to the technical factors which must be taken into account when dealing with energy, e.g. the efficiency of final energy utilization or the penetration of the market by the various energy forms.

This module incorporates two subroutines: one macro-economic subroutine (MACRO) calculates the level of activity in the production sectors taken into account and the other subroutine (DEMAND) calculates the energy demand for each category of final use. The demand by category is estimated separately for three major sectors of economic activity: households/services, industry/agriculture, and transport. The various individual demands are combined at the end of the program in order to obtain the overall demand for the country. These two subroutines combine to form a systematic framework through which the effect on energy demand of any economic, technical or social change can be quantified and evaluated.

When various forms of energy, e.g. electricity, solar energy or fossil fuels, compete for a given category of final use, the demand is first calculated in terms of useful energy and then converted into final energy, taking into account both the scenario penetration of the various competing energy forms and their efficiency. Sectoral demands for fossil fuels are estimated globally and are not broken down in terms of coal, gas and oil because such a breakdown would depend on the supply situation and on the relative prices of these fuels, two factors which are beyond the present scope of the model. The replacement of fossil energies by new forms of energy (e.g. solar energy, some electrical applications and district heating) is nevertheless considered in view of the future importance of these structural changes. Since these substitutions will essentially depend on policy decisions, they are taken into account in the construction of the scenarios.

For each category of final use, the demand for useful energy is linked to the social, economic and technical factors. In particular, the demand for electricity is the result of trends some of which are endogenous to the model whereas others are exogenous and therefore reflected in the scenarios.

A.2.1.1. Macro-economic subroutine (MACRO)

The purpose of the MACRO subroutine is to:

- Reflect in quantitative terms trends in the growth of each major economic sector defined in the qualitative scenarios,
- Ensure consistency between the development of each economic sector and the overall economy of the country.

Six economic sectors are considered in MAED: agriculture, construction, extractive industries (mining), manufacturing industries, services (including transport), and energy. The manufacturing industry sector is itself subdivided into four subsectors: the basic material industries (steel, construction materials, chemicals, etc.); capital goods (or durables) industries; food and textiles (or consumer goods) industries; and other industries which essentially comprise all the light and craft industries.

TABLE A.I. MAIN CATEGORIES OF FINAL ENERGY USE CONSIDERED IN HOUSEHOLDS/SERVICES SECTOR

$$\left.\begin{array}{l}\text{Space heating}\\ \text{Hot water}\end{array}\right\} \longrightarrow \left\{\begin{array}{l}\text{Urban area}\\ \\ \text{Rural area}\end{array}\right\} \longrightarrow \left\{\begin{array}{l}\text{Traditional}\\ \text{construction}\\ \\ \text{New (modern)}\\ \text{construction}\end{array}\right\} \longrightarrow \left\{\begin{array}{l}\text{Detached}\\ \text{houses}\\ \\ \text{Apartments}\\ \\ \text{Rooms}\end{array}\right.$$

Cooking

Air-conditioning

Specific uses of electricity

Trends in the build-up of the gross domestic product (GDP) is one of the most important factors governing the model and may be either fed in directly as scenario (related input) data or calculated by means of a set of macro-economic (linear) equations on the basis of the structure of GDP expenditure.

The macro-economic development scenario for the country may therefore be constructed either in terms of added value per sector or in terms of investment in fixed assets and expenditure.

A.2.1.2. Energy demand subroutine (DEMAND)

The demand for energy from the final consumers is calculated separately by grouping them together in three main sectors: households/services, industrial/agriculture and transport.

The demand from each sector is determined by the same method: each category of final energy use is driven by one or more socio-economic and technical factors, the values of which are defined in the scenarios.

(a) Households/services sector

Although formulated in an identical way, the domestic (i.e. households) and services sectors are in fact treated separately since their determining factors are not the same: for the households sector, the essential criterion is demographic

TABLE A.II. ALTERNATIVE FORMS OF ENERGY CONSIDERED IN HOUSEHOLDS/SERVICES SECTOR

Energy forms	Households sector					Services sector		
	Space heating	Hot water	Cooking	Air-conditioning	Specific uses of electricity	Thermal applications	Air-conditioning	Specific uses of electricity
Non-commercial fuels	X	X	X					
Fossil fuels (coal, oil, gas)	X	X	X			X		
Conventional electricity	X	X	X	X	X	X	X	X
Electricity with heat pump	X	X				X		
District heating	X[a]	X[a]				X[a]		
Soft solar systems	X[b]	X				X[c]		

[a] Only in urban areas.
[b] Only for new detached houses.
[c] Only for new low-rise buildings.

(population, number of households, etc.), whereas in the services sector it is linked to economic activity.

The uses of final energy considered in the households sector include space heating and air-conditioning, water heating, cooking and specific uses of electricity (household appliances, lifts, etc.). These estimates take into account:

- The place of residence (a large town with a high population density or the country);
- The type of construction (old traditional building or building complying with new insulation standards);
- The type of residence (detached house, flat, room).

This approach is intended to portray better the specific needs of the individuals and thus provide a clearer definition of the markets for the various forms of final energy.

Energy utilization in the services sector is broken down into: thermal applications (essentially space heating), air-conditioning, and specific uses of electricity (small machine motors, computers, lighting, etc.). The type of construction (traditional or new) is also taken into account in order to calculate the requirements for space heating and air-conditioning in this sector.

When there are several forms of energy that can be used, the estimates are expressed in terms of *useful*, instead of *final*, energy. The final energy is then calculated from market penetration scenarios for the various forms of energy. The efficiency of each energy form and of the appliances used then comes into play. For instance, in order to take into account the development of new energy forms such as solar energy, both the market penetration rate and the efficiency of the appliances must be included as parameters in the scenarios.

The demand for fossil fuels is not broken down in terms of oil, gas and coal because the MAED model does not take into account the supply problems associated with these fuels. The various categories of final use and the alternative forms of secondary energy considered for the households and services sector are summarized in Tables A.I and A.II.

(b) Industrial sector

The industrial sector comprises four economic activities: agriculture, construction, mining, and manufacturing industries. The latter is itself broken down into four subsectors: basic materials (steel, chemicals, etc.), durables, non-durables or consumer goods (food and textiles), and other industries which comprise all other types of industry, including crafts.

The energy demand of each sector is essentially determined by the level of activity in the sector, as evaluated in terms of its added value. The level of activity in each sector is either derived from the macro-economic subroutine or introduced into the scenario when it is constructed.

Within each sector, the final energy demand is divided into three categories: specific uses of electricity (lighting, motive power, electrolysis, etc.), thermal applications (space heating, hot water, steam generation, furnaces and direct heat), and motor fuels. Coke used in steel production and chemical feedstocks is treated separately.

The specific uses of electricity and motor fuels are considered non-replaceable. Substitution of energy forms is possible in the case of thermal applications, particularly in the manufacturing industries. The demand for energy in agriculture, construction and mining is calculated directly in terms of final energy. The same applies to the demand for specific, non-replaceable uses of electricity and for motor fuels in the manufacturing industries. Replaceable thermal applications in the manufacturing industries are estimated in terms of useful energy.

The interchangeability of energy forms in the manufacturing industry subsectors is derived from the assumed penetration of the energy market by the various forms of energy in the scenario. The thermal applications are broken down into three temperature ranges: low (space heating, hot water and steam generation for process temperatures between 80°C and 120°C); medium (steam generation for process temperatures greater than 120°C) and high (furnaces and direct heat).

Since the level of economic activity determines energy consumption in each sector, it is necessary to establish the specific energy intensities in each economic sector, per category of use. The characteristic intensities (expressed as the amount of energy per unit of value added) for each country are introduced exogenously. Market penetration by alternative energy forms is calculated from the scenario data and from the technical coefficients expressing the efficiency of each energy form in relation to electricity.

The demand for useful energy (in the case of replaceable energy forms) is converted into final energy by a process for simulating market penetration similar to that described for the households/services sector.

The activities included in the industrial sector, the various end-use applications and the alternative forms of secondary energy are summarized in Tables A.III and A.IV.

(c) Transport sector

The demand for final energy in the transport sector is a function of the demand per mode of transport (car, train, plane, etc.), the specific energy needs of each mode of transport, and the load factors applying to each mode. The transport demand is estimated according to macro-economic factors including population size and distribution, urban and intercity passenger transport requirements, and the value added in the industrial and agricultural sectors relating to the different products. A saturation effect can be introduced by means of an exogenous scenario variable.

TABLE A.III. ACTIVITIES AND CATEGORIES OF ENERGY USE CONSIDERED IN THE INDUSTRIAL SECTOR

Activities:

Agriculture
Construction
Extractive industries
Manufacturing industries, including:
- Basic products (steel, chemicals, etc.)
- Durable goods (machinery and equipment)
- Consumer goods (food, textiles, etc.)
- Others (crafts, etc.)

Energy uses:

Specific uses of electricity (lighting, motive power, electrolysis, etc.)
Motor fuels
Thermal applications:
- Low temperature: hot water, space heating, and steam for process temperatures 80–120°C
- Medium temperature (>120°C steam)
- High temperature (furnaces and industrial heat)
- Special treatment for:
  - Coke for reducing pig-iron in steelworks
  - Feedstocks in the petrochemical industry

Since the trends in the proportional use of the various modes of transport are essentially influenced by government policy, all changes in past trends are introduced exogenously via the scenarios. If no change is introduced, the distribution between various modes of transport is calculated on the basis of functions trimmed according to past trends. With the exception of the car, where substantial improvements in specific consumption may be expected in the future, the specific consumption figures for the other modes of transport are deduced from past trends. The load factors depend on transport policy and must therefore be included as specific scenario components.

The types and modes of transport, together with the alternative forms of secondary energy considered for the transport sector are listed in Tables A.V and A.VI.

A.2.2. Module 2: hourly electric power demand

The purpose of this module is to convert the global annual demand for electricity (in GW·h) of each economic sector to the demand broken down on an hourly basis, i.e. to the demand for electric power (in MW) imposed on the

TABLE A.IV. ALTERNATIVE ENERGY FORMS CONSIDERED IN THE INDUSTRIAL SECTOR

Energy forms	Agri-culture	Con-struction	Extractive industries	Manufacturing industries				
				Specific uses of electricity	Conventional motors	Thermal applications		
						Low Temp.	Med. Temp.	High Temp.
Fossil fuels (coal, oil, gas)	X	X	X			X	X	X
Conventional electricity	X	X	X	X		X	X	X
Electricity with heat pump				X		X	X	
Motor fuels	X	X	X		X			
District heating						X	X	
Cogeneration						X		
Soft solar systems						X		

TABLE A.V. TYPES AND MODES OF TRANSPORT CONSIDERED IN THE TRANSPORT SECTOR

Passenger transport[a]	
Urban	Cars
	Public transport
Intercity	Cars
	Trains
	Buses
	Planes
Freight transport[a]	
Local	Trucks
Long-distance	Trucks
	Trains
	Barges/coastal shipping
	Pipelines
International transport	Planes
	Ships

[a] On the national scale.

TABLE A.VI. ALTERNATIVE ENERGY FORMS PER CATEGORY OF USE CONSIDERED IN THE TRANSPORT SECTOR

Mode of transport	Motor fuels	Electricity	Other thermal fuels (coal)
Cars	X	X[a]	
Urban public transport	X	X	
Trains	X	X	X
Buses	X		
Trucks	X		
Planes	X		
Barges	X		
Ships	X		
Pipelines	X		

[a] For urban transport only.

distribution grid by each sector. This analysis is carried out using the various 'modulation factors' describing variations in electricity consumption about a mean trend. The annual energy demand is converted to the demand imposed on the grid at a particular time, on a particular day of a given week, by taking into account:

- The trend in the average growth of electricity demand during the year;
- Seasonal variations in electricity consumption (measured in monthly or weekly terms, depending on the information available);
- The impact of the type of day in question (working day, weekend, special holiday);
- Hourly variations in electricity consumption during the given type of day (working day or holiday).

Each of these time sequences has its own modulation coefficient which, when multiplied, provides the correction to the mean hourly consumption rate. When the modulation coefficients are known for each sector, the electricity demand over the 8760 hours of the year can be calculated. In graph form, the result is what is known as the load curve, or the curve of the demand imposed on the grid by the sector in question. When the load curves of each sector are known, the annual grid load curve can be plotted by summing the hourly individual curves.

It should be noted that the modulation coefficients for each sector can be determined only on the basis of statistical studies covering several past years. Various statistical studies have shown that the modulation coefficients for a given sector vary only very slightly over the years. A country's load curve is much more a function of variations in the proportion of energy consumed in each economic sector than of variations in the various (seasonal, daily or hourly) modulation coefficients for each of these sectors.

The modulation coefficients for the different sectors are usually estimated on the basis of the most recent consumer surveys available. These coefficients are commonly held constant throughout all the years of the study period. In practice, this does not pose any great difficulties because the values of the coefficients for each sector are statistically very stable. The weighting to be attributed to each sector according to its share in the total consumption has a much greater impact, which is obviously taken into account.

A.2.3. Module 3: load duration curve

This module is used to switch from a chronological representation of the demand imposed on the electric grid to the format required in order to study the optimization of the electricity generating capacity using the WASP model. Module 3 of the MAED model uses the 8760 values of demand imposed on the grid (calculated by Module 2) and arranges them in decreasing order. The time duration of all demands of the same size are added up so that the annual load duration curve for the grid can be plotted. This curve is then normalized by dividing each value of demand by the maximum demand in the year and its respective time duration by 8760. The normalized load duration curve for each year constitutes important input data for the WASP model.

Figure A.2 illustrates how Modules 2 and 3 of MAED are to be executed, as well as the type of output information produced by each module and the interconnection with the WASP model.

A.2.4. Module 4: load modulation coefficient

This module is considered as an auxiliary tool of MAED. It may be used in order to determine the various load modulation coefficients (trend, seasonal, daily and hourly) characterizing the total system power demand in a given year. Execution of this module for several years of past experience for the electric system under consideration may be very useful in the analysis of the power demand characteristics of the system and of their variations with the years.

A.3. ORGANIZATION OF MAED-1

The general structure of MAED is shown in Fig. A.3, which also illustrates the flow of information from the modules and associated data files. The number given to each module indicates the proper sequence of their execution:

Module 1 (energy demand) processes information describing the macroeconomic and technological scenario of development and calculates the total energy demand for the desired years. The breakdown of this demand by energy form and by economic sector considered is also provided as part of the results of the analysis. This module creates a file, LOADSCEN, to be used later by Module 2. A scratch file, TEMP, is also used as a temporary working file by Module 1.

Module 2 (hourly electric power demand) uses the total annual demand of electricity for each sector (contained in file LOADSCEN) to determine the total electric power demand for each hour of the year or, in other words, the hourly electric load which is imposed on the power system under consideration. During its execution this module creates a file, LOADYEAR, to be used by Module 3.

Module 3 (electric load duration curve) uses the hourly loads (contained in file LOADYEAR) to produce the load duration curve of the power system as required for the execution of a WASP study. Two output files are created by this module during execution. The first file, LOADWASP, contains the WASP input data, and the second file, LOADPLOT, contains the same information but presented in a different format, as required for plotting the load duration curve.

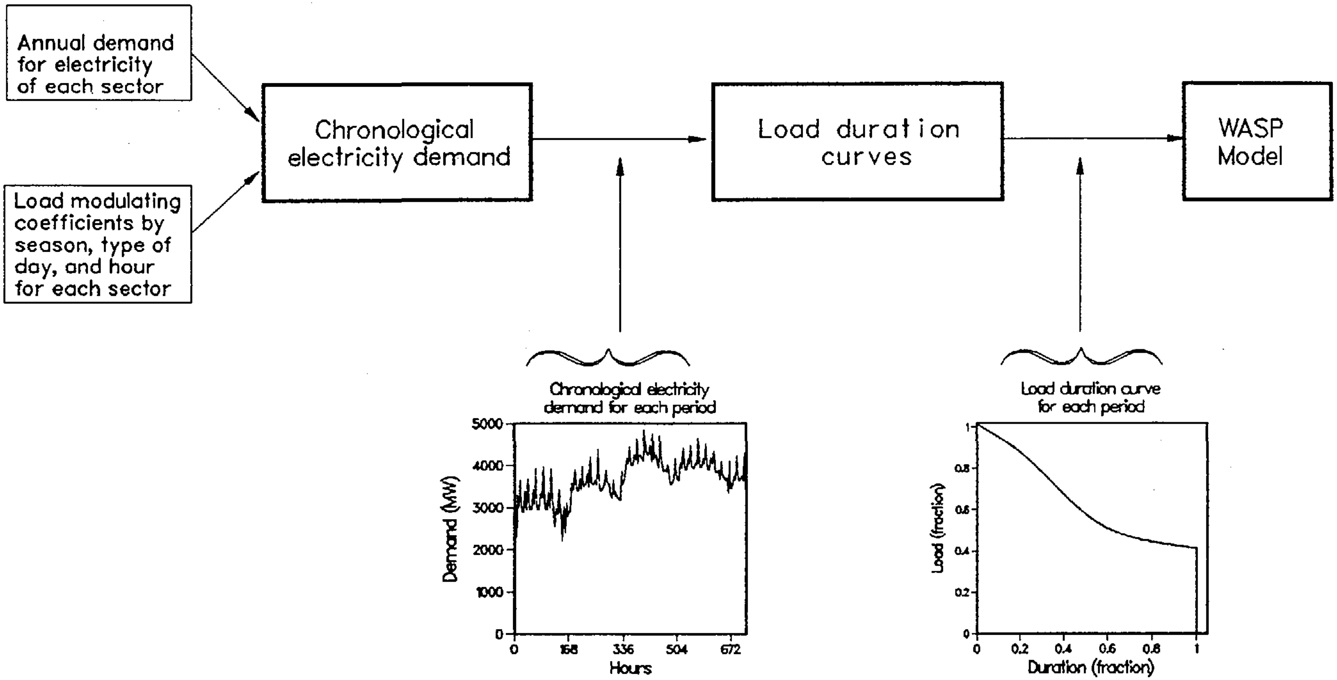

FIG. A.2. MAED estimates of load duration curves for input to WASP.

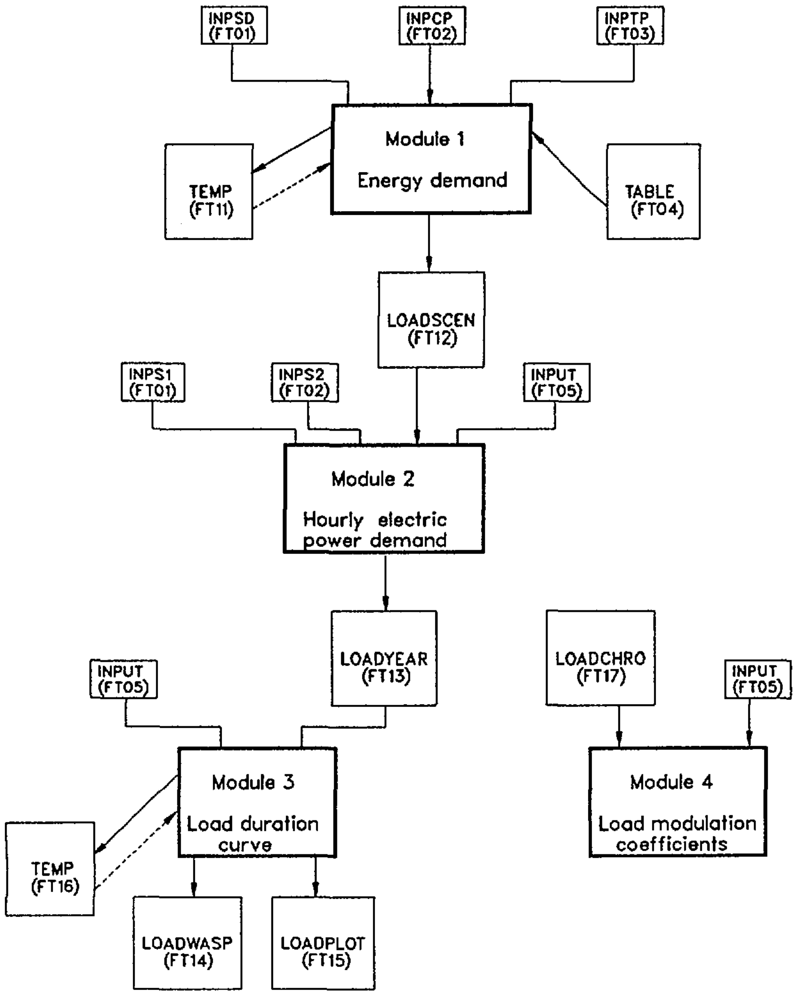

FIG. A.3. Organization of the MAED computer program.

Module 4 (load modulation coefficients) is an auxiliary module which may be used to analyse the past evolution of the coefficients describing the variation of the hourly electric loads, based on load curves determined from statistical data. An additional input file, LOADCHRO, with the chronological electric power demand hour by hour for past years of statistics, is required for the execution of this module. As can be seen in Figure A.3, no output file is created by this module.

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Appendix B

THE MNI MODEL*

B.1. SCOPE

B.1.1. Interaction between generation and transmission planning

Overall power system planning should ideally cover generation and transmission in a single formulation. However, owing to the size and complexity of the problem, this is unlikely to be computationally feasible in most countries. A number of system planners have therefore adopted a decomposition method between generation and transmission planning, as follows:

(a) Determining the generation system expansion as a one-node exercise excluding network considerations and assuming that demand and generating facilities are concentrated at the same point;
(b) Deducing the corresponding optimal power plant siting and network expansion.

Iterations would be carried out as necessary. Such a decomposition approach is generally justified if:

- The network is adequately interconnected,
- The lead time for a line is shorter than that for a plant,
- The total investment costs for the transmission system are much smaller than those for generation.

This is the case in France, where generation facilities are located not too far from the consumption centres.

B.1.2. Models for generation expansion planning [1–4]

A number of models have been developed and used by Electricité de France (EDF) for long- and medium-term generation planning: MNI, Chain P, RELAX, ENTRET. They are not integrated into a single computer program; each of the four models deals with a specific subproblem of the global generation planning problem as follows:

- MNI for long-term generation planning,
- Chain P for medium-term production costing,
- RELAX for medium-term maintenance and refuelling of nuclear PWR units,
- ENTRET for medium-term maintenance of conventional thermal plants.

* MNI stands for Modèle National d'Investissement (National Investment Model), developed in France.

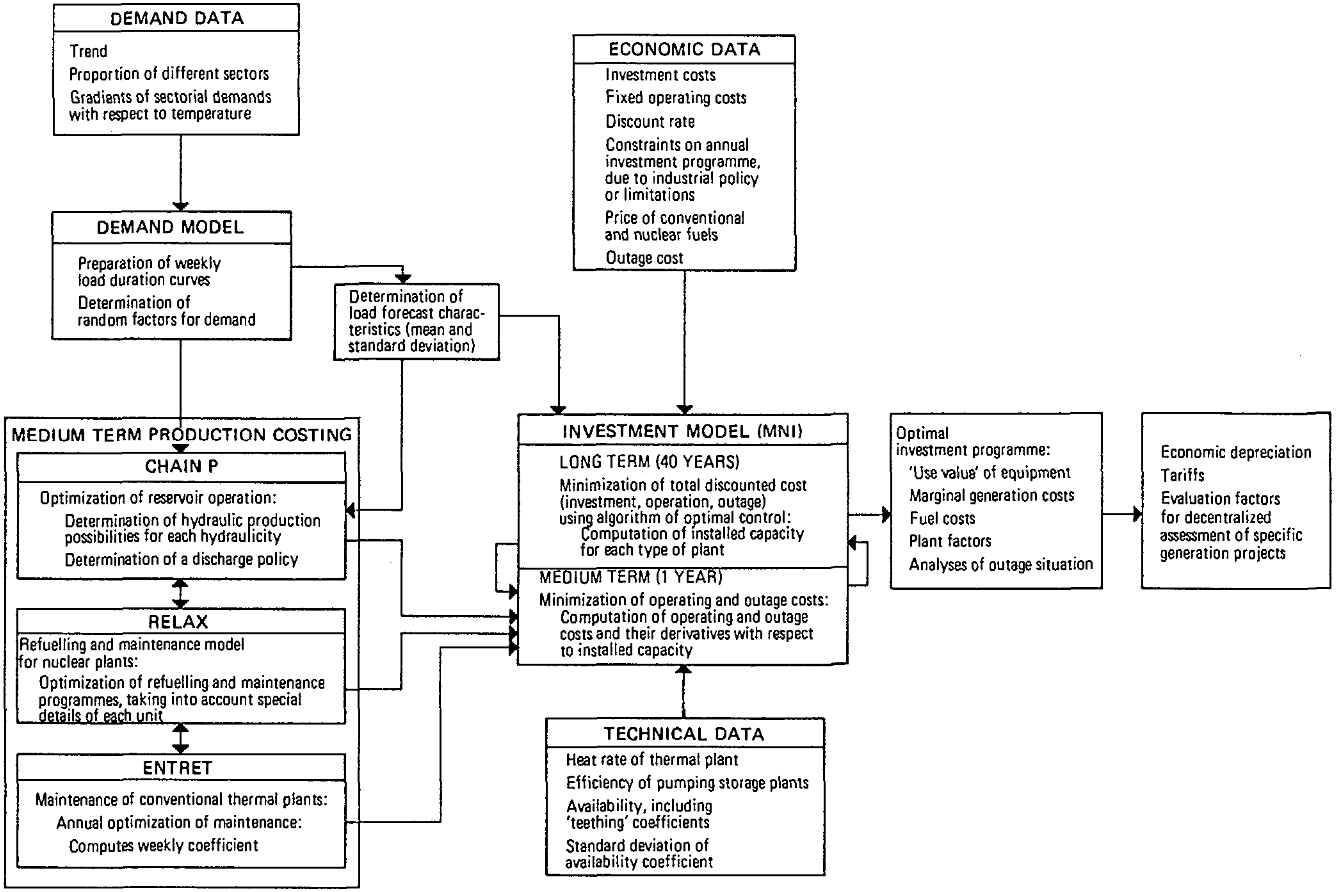

FIG.B.1. Interaction between Electricité de France computer models.

MNI and ENTRET use optimal control methods. RELAX uses dynamic programming with a relaxation technique between the different nuclear units. Chain P uses stochastic optimal control with price decomposition and co-ordination between the different hydraulic valleys. For the interactions between these models, see Fig.B.1. (This appendix describes the MNI model only.)

B.2. OBJECTIVE

The objective of the MNI model is to minimize the total present worth of investment, expected generation and outage costs, discounted at a given rate (public sector discount rate) over several decades. Estimates for generating facilities capital, O&M costs and fuel prices are entered as deterministic data, while demand, hydrological conditions and unscheduled plant outages are treated as random variables.

Plants are not considered individually: they are aggregated into different types, for which mean and standard deviation of availability are computed. The MNI model has only continuous variables.

For brevity, a very simple version of the MNI is first described, in which the objective function is:

$$\mathrm{MIN} \sum_{t=1}^{T-1} \left[\sum_{i} I_i^t U_i^t + G^t(X_i^t + U_i^t) \right] + S^T(X^T)$$

subject to

$$0 \leqslant U_i^t$$

$$X_i^{t+1} = X_i^t + U_i^t$$

$$X_i^0 = \text{initial state (known)}$$

I_i^t is the discounted unit investment cost associated with plant of type i (including the discounted sum of annual fixed charges and replacement by the same type at end of lifetime);

U_i^t is additional capacity of type i commissioned in year t;

$G^t(X_i^t + U_i^t)$ is expected discounted generation and outage costs during year t, given the system structure $X_i^t + U_i^t$ in that year;

$S^T(X^T)$ is the end effects adjustment.

B.3. CONSTRAINTS

In the MNI model the constraints on the optimization are expressed as upper and lower bounds on the admissible generation additions for each generation alternative. A significant departure from US practice is the absence of reliability constraints. Reliability is considered as part of the cost function. An outage cost is computed for the unsupplied energy and added to the investment and fuel cost.

B.4. TIME HORIZON

This must obviously be at least of the order of magnitude of the service life of the plants. Since computation time increases linearly with the number of study periods, the compromise chosen in the MNI was to represent:

(a) Each of the first 15 years of the time horizon by one time step;
(b) The subsequent years by time steps of three or five years, thus allowing a time horizon of 40–50 years with reasonable computation requirements.

B.5. METHOD OF SOLUTION

The MNI long-term expansion problem is formulated with continuous variables as an optimal control problem using Pontryagin's maximum principle. It is solved by a steepest descent algorithm.

The main difficulty of this problem arises from its large scale. One must not forget that the operating and outage cost G^t is itself the result of the medium-term stochastic production model with fixed equipment.

B.5.1. Optimality conditions

The Pontryagin maximum principle is used to formulate the optimality conditions in the simplest case where the only constraint on U_i^t is $U_i^t \geqslant 0$.

The original dynamic problem can be decomposed into several static problems. The Hamiltonian is:

$$\mathscr{H}^t = -\left[\sum_{i=1}^{n} I_i^t U_i^t + G^t(X^t + U^t)\right] + \sum_{i=1}^{n} \psi_i^{t+1} U_i^t$$

The adjoint system is:

$$\left|\begin{aligned}&\psi_i^{t+1} = \psi_i^t + \frac{\partial G^t}{\partial X_i^t}\\ &\psi_i^T = \frac{\partial S^T}{\partial X_i^T}\end{aligned}\right. \qquad \text{(B.1)}$$

which can be solved by backward integration as follows:

$$\psi_i^t = -\sum_{\tau=t}^{T-1} \frac{\partial G^\tau}{\partial X_i^\tau} - \frac{\partial S^T}{\partial X_i^T} \qquad (i = 1 \text{ to } n)$$

The optimum control is given by the maximization of the Hamiltonian:

$$\underset{U_i^t}{\text{Max}} \left[\sum_{i=1}^{n} (\psi_i^{t+1} - I_i^t)\, U_i^t - G^t(X^t + U^t) \right] \qquad U_i^t \geqslant 0$$

Using the Kühn and Tucker theorem,

$$\left|\begin{aligned}&\psi_i^{t+1} - I_i^t - \frac{\partial G^t}{\partial U_i^t} = 0 \quad \text{if } U_i^t > 0\\ &U_i^t = 0 \quad \text{if } \psi_i^{t+1} - I_i^t - \frac{\partial G^t}{\partial U_i^t} < 0\end{aligned}\right. \qquad (i = 1 \text{ to } n) \qquad \text{(B.2)}$$

B.5.2. Economic interpretation

Considering the following formulation:

$$\psi_i^t = \sum_{\tau=t}^{T-1} \frac{\partial G^\tau}{\partial X_i^\tau} - \frac{\partial S^\tau}{\partial X_i^T} \qquad (i = 1 \text{ to } n)$$

the component ψ_i^t of the co-state vector ψ^t appears as the sum of future savings of operating cost and outage cost provided by the additional kW of plant i at time t. The definition of the 'value of use' of plant i is as follows:

ψ_i^t = value of use of plant i at time t

Since economic depreciation is precisely the loss in the value of use during year t, we can write:

$\psi_i^{t+1} - \psi_i^t$ = economic depreciation of plant i at time t

B.5.3. Net marginal gains

We have stated the Kühn and Tucker conditions related to the maximization of the Hamiltonian with respect to U^t. Since G is a function of $(X^t + U^t)$ we have:

$$\frac{\partial G^t}{\partial X_i^t} = \frac{\partial G^t}{\partial U_i^t} \qquad (i = 1 \text{ to } n)$$

Thus the Kühn and Tucker condition (B.2) becomes:

$$\left| \begin{array}{l} \psi^{t+1} - I_i^t - \dfrac{\partial G^t}{\partial X_i^t} = 0 \quad \text{if } U_i^t > 0 \\[2ex] U_i^t = 0 \quad \text{if } \psi_i^{t+1} - I_i^t - \dfrac{\partial G^t}{\partial X_i^t} < 0 \end{array} \right.$$

Taking the dual system (B.1) into account:

$$\psi_i^{t+1} = \psi_i^t + \frac{\partial G^t}{\partial X_i^t}$$

we obtain:

$$\begin{array}{l} \psi_i^t - I_i^t = 0 \quad \text{if } U_i^t > 0 \\[1ex] U_i^t = 0 \quad \text{if } \psi_i^t - I_i^t < 0 \end{array} \tag{B.3}$$

At the optimum, the investment cost and the value of use are equal except when the constraint $U_i^t \geqslant 0$ is active.

B.5.4. Algorithm

The preceding optimality conditions lead to a simple steepest descent algorithm:

$$U_i^t \text{ (at iteration } k+1) = \underbrace{U_i^t + k_i^t(\psi_i^t - I_i^t)}_{\text{at iteration } k}$$

Parameters k_i^t are arbitrary, except that they should be positive. However, their choice influences the performances of the algorithm. The following ideas have proved helpful to accelerate convergence:

- To decide homogeneous displacements, relative net marginal gains, $(\psi_i^t - I_i^t)/I_i^t$ are used, rather than absolute marginal gains $(\psi_i^t - I_i^t)$;
- Each year the displacements are proportional to the variation of the mean peak demand from one year to another, Δ^t;
- Therefore $k_i^t = \theta\ (\Delta^t/I_i^t)$, where θ is a parameter $(0 < \theta < 1)$.

B.5.5. Automatic tuning of parameter θ

Recall that δU_i^t, the change in the control variable from one iteration to the next, is:

$$\delta U_i^t = \theta \Delta^t \frac{\psi_i^t - I_i^t}{I_i^t}$$

The parameter θ is of great practical importance: it determines the computational requirements of the algorithm since the number of iterations needed for convergence will greatly depend on the choice of θ. Indeed, if θ is too large, δC, the change in the total cost criterion to be minimized, might be positive from one iteration to the other. Then one has to go back (taking $\theta/2$ for example). On the other hand, if θ is too small, too many iterations will be needed.

Now if we call ψ the angle made by two successive directions of search δU, we may notice that:

- (θ too large) is equivalent to ($\cos\psi < 0$): θ should be reduced.
- (θ too small) is equivalent to ($\cos\psi > 0$): θ should be increased.
- (θ optimal) is equivalent to ($\cos\psi = 0$).

As we know that $\cos\psi$ can be computed as:

$$\frac{\delta U^N U^{N-1}}{||\delta U^N||\ \ ||\delta U^{N-1}||}$$

we retain $\theta^{(N)} = K^{\cos\psi}\theta^{(N-1)}$ (with $k = 2$).

In this way the algorithm parameter θ is automatically updated at each iteration. This special device has substantially reduced the number of iterations necessary for convergence.

B.5.6. Retirement of old plants

MNI simultaneously optimizes the investment of new plants and the retirement of old plants. This attractive feature of MNI is explained below.

Let j be the current index of old plants (facilities in service at the beginning of the generation expansion study period). Specific constraints related to those types of plant should be added to those mentioned in Section B.3:

(a) $X_j^t \leqslant X_{j\max}^t$ ($X_{j\max}^t$ is determined by the end of lifetime of old plants);

(b) $X_j^t = 0$ (as the length of the study period in MNI is of the order of magnitude of the lifetime of new plants, we are sure that the old plants will have to be retired before T).

For easier solution of the optimization problem, these state (X) constraints are transformed into the equivalent control (U) constraints:

$$\text{(a)} \quad X_j^0 + \sum_{r=1}^{t-1} U_j^r \leqslant X_{j\max}^t$$

$$\text{(b)} \quad X_j^0 + \sum_{r=1}^{T-1} U_j^r = X_{j\max}^T = 0$$

The problem to be solved can now be written as follows (in this formulation, only the modifications to the simple version given earlier are mentioned):

$$\text{MIN} \sum_{t=0}^{T} - \sum_{j} P_j^t U_j^t + F^t(X^t + U^t) + G^t(X^t, U^t)$$

$$X_j^t = X_j^{t-1} + U_j^{t-1}$$

$$U_{j\min}^t \leqslant U_j^t \leqslant U_{j\max}^t$$

$$(1)\quad X_j^0 + \sum_{r=1}^{t-1} U_j^r < X_{j\,max}^t$$

$$(2)\quad X_j^0 + \sum_{r=1}^{T-1} U_j^r = 0$$

X_j^0 GIVEN

where P_j^t is the unit staff resorption cost per kW.

The algorithm given previously has only to be made slightly more sophisticated in order to take into account the additional constraints (1) and (2).

B.6. PRODUCTION COSTING

The MNI model uses load duration curves in the production cost simulation. As short-term fluctuations of demand are increasing and as pumped storage plants need to be studied on a weekly basis, there are, for a one-year period, 52 discrete load duration curves with seven levels corresponding to specific periods of the working days and the week-end.

The pumped storage hydroelectric plant optimized in the MNI is run on a weekly cycle. The MNI includes a constraint which ensures that water levels are returned to the same level at the end of each week.

The model of a conventional hydroelectric plant consists of a stochastic optimal control model which considers, explicitly, all the site constraints and, individually, all the hydro complexes. This model (Chain P) was designed and is currently used in the annual operating cycle of EDF to decide the weekly releases at each large seasonal dam.

Hydroelectric generation is thus represented accurately and consistently between the investment and operation levels (long and medium term). Total hydroelectric generation for several years into the future is used as input for the MNI model itself. Some interactions between MNI and Chain P could therefore be necessary.

In the same way, the MNI model includes (interacting with a specialized model) optimized maintenance schedules for conventional and nuclear units.

The maintenance schedule for each type of equipment, M_i^t, and the probability law of conventional hydroelectric generation are optimized decision variables in the problem formulated above. Given these energy management decisions, the production costing problem is solved on a weekly basis by deterministic analyses repeated for several occurrences of the random variables (load, water inflows, thermal forced outages). Computations are repeated for selected combinations of these three random variables to represent the full spectrum of occurrence, and the results are weighted according to the associated probabilities.

The production costing model also determines the cost gradient vector with respect to all capacities of equipment considered at the investment level (thermal and pumped storage). This result is used in the optimization to determine the direction of search.

B.7. PRESENT STATUS OF THE MNI MODEL

Three further important features of the MNI model currently used by EDF are the following:

- 'Teething troubles' with new plants are taken into account.
- Upper and lower limits on plant expansion are considered ($U_i^t \min \leqslant U_i^t \leqslant$ $\leqslant U_i^t \max$).
- Special devices are used to limit the number of elementary situations to be studied in the production costing model, i.e. when the optimum is far from being reached, a rough estimate of the operating and outage cost is sufficient; the number of simulated situations increases when the optimum approaches.

B.8. USES OF THE MNI MODEL

The MNI model automatically selects a generation expansion plan from a set of alternative sources of generation: nuclear, coal, oil, gas turbines, pumped storage (operating on a weekly basis).

B.8.1. Sensitivity analysis

A useful feature for power system planners is the sensitivity information provided by the dual variables related to the various constraints of the planning problem. Thus, the MNI model computes the co-state variables ψ which can be interpreted as the value of use of a certain plant addition. It is in fact the sensitivity of the total system cost to the addition of 1 kW in that plant capacity.

B.8.2. Global and marginal analysis

Hydroelectric generation is preselected in the MNI since all major available sites in France are already harnessed. However, some small hydroelectric plants have not yet been constructed. In addition, changes in the design of existing plants and seasonal pumped storage plants could be made. Therefore, the MNI results include all the necessary economic information (marginal production costs) to select the most profitable projects and optimize each project design.

B.8.3. MNI helps project design: marginal analysis

Recall the optimality conditions for a plant in expansion:

Investment cost $^{\bullet}$ = value of use (without constraint on U_i^t)
= Σ future discounted savings minus Σ future discounted fixed operating costs

Since

Operating savings = marginal cost minus operating cost

We find:

Investment cost + Σ total operating cost = Σ marginal costs

This equation is used for decentralized economic studies within EDF ('Blue Notes') after an appropriate aggregation of marginal costs has been calculated from the global approach performed by the MNI model.

Thus, all projects of small size, naturally marginal, can be studied according to a marginal method. The following would be easily dealt with by a marginal method:

- Determining the optimal size and design of classical hydraulic plants (very few are still to be built in France),
- Optimizing detailed parts of nuclear plants (e.g. cooling devices).

Marginal methods should be used with caution to determine the optimal amount of pumped storage plants to be developed.

A simplified and aggregated representation of the costs of the individual projects should be used inside the investment model. Estimates are provided by preliminary studies. If these are correct, the total amount of profitable projects will not be very different from the results of the model.

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Appendix C

RECENT TECHNIQUES FOR PRODUCTION COST SIMULATION

C.1. INTRODUCTION

There has been much recent interest in innovative approaches to evaluating production cost in generation planning by means of probabilistic simulation. This Appendix describes two computationally efficient techniques that are particularly suited for generation expansion planning studies: the *cumulant method* (sometimes also called method of moments) and the *segmentation method.* For a realistic set of expansion candidates, planning horizons and simulation intervals, these studies would require the probabilistic simulation of thousands of feasible system configurations, hence the need for such efficient techniques.

C.2. THE CUMULANT METHOD

The cumulant method has been shown to be an effective and efficient technique for evaluating loss of load probability (LOLP) and production costs in generation planning for large systems [1–5]. This method is based on the analytical representation of the equivalent load distribution (ELDC) using the Gram-Charlier Type A or the Edgeworth expansion. The basic procedure rests on the observation that the cumulants of a sum of independent random variables (RVs) are equal to the sum of the respective cumulants. Thus convolution is simply simulated by the addition of cumulants and, conversely, deconvolution is simulated by the subtraction of cumulants.

Although computationally very efficient (by about an order of magnitude as compared to the commonly used Booth-Baleriaux method with a recursive formula and numerical integration or with a Fourier series method as in WASP-III), the method is subject to the inherent inaccuracies of expansions such as the Gram-Charlier series [6].

The accuracy of the basic technique depends on a number of factors: unit forced outage rates (FORs), size and number of units, shape of the ELDC, etc. In particular, for small systems with plants with small FORs (<0.05) and large unit size, the method has sometimes shown unexpected behaviour [7–9]. Much work has been reported recently on overcoming such inaccuracies [10]. One effective technique adds 'error moments' to the original moments of the load frequency distribution. These error moments are obtained from the difference between the original load distribution or load duration curve (LDC) and the analytical representation obtained from the Gram-Charlier Type A or Edgeworth expansion. This process may be repeated iteratively until a good fit of the LDC is obtained.

C.2.1. Gram-Charlier Type A and Edgeworth expansions

Assume an RV, X, with finite moments, with a probability density function (PDF), f(x). In terms of a standardized RV, Z, the Gram-Charlier (Type A) expansion is defined as (up to eight moments [11, 12]):

$$f(z) = N(z) - \frac{G_1}{3!} N^{(3)}(z) + \frac{G_2}{4!} N^{(4)}(z) - \frac{G_3}{5!} N^{(5)}(z) + \frac{(G_4 + 10G_1^2)}{6!} N^{(6)}(z)$$
$$- \frac{(G_5 + 35G_1 G_2)}{7!} N^{(7)}(z) + \frac{(G_6 + 56G_1 G_3 + 35G_2^2)}{8!} N^{(8)}(z) \qquad \text{(C.1)}$$

in which

$$Z = \frac{X - \mu}{\sigma} \qquad \text{(C.2)}$$

and

$$N(z) = \frac{1}{\sqrt{2\pi}} \exp(-z^2/2) \qquad \text{(C.3)}$$

and μ and σ are the mean and standard deviation of the RV, X, respectively. The Edgeworth expansion is given by (up to six moments):

$$\begin{aligned} f(z) = N(z) &- \frac{G_1 N^{(3)}(z)}{3!} + \left[\frac{G_2 N^{(4)}(z)}{4!} + \frac{10G_1^2 N^{(6)}(z)}{6!}\right] \\ &- \left[\frac{G_3 N^{(5)}(z)}{5!} + \frac{35G_1 G_2 N^{(7)}(z)}{7!} + \frac{280G_1^3 N^{(9)}(z)}{9!}\right] \\ &+ \left[\frac{G_4 N^{(6)}(z)}{6!} + \frac{35G_2^2 N^{(8)}(z)}{8!} + \frac{56G_1 G_3 N^{(8)}(z)}{8!}\right. \\ &\left. + \frac{2100G_1^2 G_2 N^{(10)}(z)}{10!} + \frac{15400G_1^4 N^{(12)}(z)}{12!}\right] \end{aligned} \qquad \text{(C.4)}$$

with the same definitions for the variables and factors G_ν. The Edgeworth expansion consists of a rearrangement of the terms of the Gram-Charlier expansion.

The factors G_ν in Eqs (C.1) and (C.4) are obtained in terms of the cumulants k_ν as follows:

$$G_\nu = \frac{k_{\nu+2}}{\sigma^{\nu+2}} \quad (\nu = 1, 2, 3, \ldots) \tag{C.5}$$

The derivatives of the normal PDF satisfy the recursive relation:

$$N^{(r)}(z) = -(r-1)N^{(r-2)}(z) - zN^{(r-1)}(z) \quad (r = 3, 4, 5, \ldots) \tag{C.6}$$

with $N^{(1)}(z) = -zN(z)$ and $N^{(2)}(z) = (z^2 - 1)N(z)$.

The cumulants may be obtained from the central moments which, in turn, may be obtained from the moments about the origin. The moments (about the origin) of the RV, X, with a PDF, f(x), are given by (the zeroth-order moment for a well-defined PDF is always unity, i.e. $m_0 = 1$):

$$m_r = \int_{-\infty}^{\infty} x^r \, f(x)\, dx \quad (r = 0, 1, 2, \ldots) \tag{C.7}$$

The central moments are given by[1]:

$$\mu_r = \sum_{j=0}^{r} \binom{r}{j} m_{r-j}(-m_1)^j \quad (r = 1, 2, 3, \ldots) \tag{C.8}$$

and the cumulants, up to the eighth order, are given by:

$$k_1 = m_1 \qquad k_5 = \mu_5 - 10\mu_3\mu_2$$
$$k_2 = \mu_2 = \sigma^2 \qquad k_6 = \mu_6 - 15\mu_4\mu_2 - 10\mu_3^2 + 30\mu_2^3$$
$$k_3 = \mu_3 \qquad k_7 = \mu_7 - 21\mu_5\mu_2 - 35\mu_4\mu_3 + 210\mu_3\mu_2^2$$
$$k_4 = \mu_4 - 3\mu_2^2$$

$$k_8 = \mu_8 - 28\mu_6\mu_2 - 56\mu_5\mu_3 - 35\mu_4^2 + 420\mu_4\mu_2^2 + 560\mu_3^2\mu_2 - 630\mu_2^4$$

---

[1] $\mu_2 = m_2 - m_1^2$; $\mu_3 = m_3 - 3m_2m_1 + 2m_1^3$; $\mu_4 = m_4 - 4m_3m_1 + 6m_2m_1^2 - 3m_1^4$; etc.

To evaluate unserved energy it is necessary to obtain the integral:

$$UE = T \int_{z_1}^{\infty} f(z)\, dz \tag{C.9}$$

in which T is the time period under consideration. Integrating Eq. (C.1) gives:

$$P(Z \geqslant Z_1) = \int_{Z_1}^{\infty} N(z)\, dz + \frac{G_1}{3!} N^{(2)}(z_1) - \frac{G_2}{4!} N^{(3)}(z_1)$$

$$+ \frac{G_3}{5!} N^{(4)}(z_1) - \frac{(G_4 + 10G_1^2)}{6!} N^{(5)}(z_1) + \frac{(G_5 + 35G_1G_2)}{7!} N^{(6)}(z_1)$$

$$- \frac{(G_6 + 56G_1G_3 + 35G_2^2)}{8!} N^{(7)}(z_1) + \ldots \tag{C.10}$$

The integral of the normal PDF may be conveniently evaluated from the closed form relation:

$$\int_{z_1}^{\infty} N(z)\, dz = \begin{cases} Q(z_1) & z_1 \geqslant 0 \\ 1 - Q(z_1) & z_1 < 0 \end{cases} \tag{C.11}$$

$$Q(z_1) = N(z_1)\,[0.319381530t - 0.356563782t^2 + 1.781477937t^3$$

$$- 1.821255978t^4 + 1.330274429t^5] + \epsilon(z_1) \tag{C.12}$$

where

$$\epsilon(z_1) < 7.5 \times 10^{-8} \tag{C.13}$$

and

$$t = \frac{1}{1 + 0.2316419\,|z_1|}$$

C.2.2. Basic procedure

There are two basic variations of the cumulant method based on the Gram-Charlier or Edgeworth expansion. One variation starts with the chronological load curve. By sampling this curve every hour, or any other desired time interval, and assigning equal probability to each sample, the load PDF is obtained from which the moments and cumulants are easily evaluated. By adding the cumulants corresponding to the RV of machine outage capacity, the cumulants of the PDF of equivalent load are obtained. This PDF is expressed in terms of the Gram-Charlier or Edgeworth expansion. Integrating this series twice gives areas under the load distribution from which the unserved energies may be obtained in a straightforward manner. The difference in unserved energies before and after the unit is committed is equal to the expected energy met by the unit. Multiplying by the average incremental cost gives the expected unit production cost.

The second variation starts with a normalized LDC (or load probability distribution) and obtains its moments and cumulants. Adding the cumulants of capacity outages of the generating units gives the cumulants of the ELDC. This ELDC is expressed in terms of the Gram-Charlier or Edgeworth expansion. Integrating this series once gives the unserved energies from which the unit expected energy generation is obtained. Both variations give very similar results and are equally computationally efficient if the time taken to order the load to obtain the LDC is not included in the second variation. Thus, if the starting point is the chronological load curve, then Variation 1 is preferred. If the LDC is available, Variation 2 is preferred.

C.2.3. Step-by-step procedure

Variation 1 is outlined below. Variation 2 follows a similar procedure.

Step 1: Sample the chronological load curve every hour (or any other time interval) and assign to each hour equal probability to obtain the discrete PDF of load.

Step 2: Obtain the moments and cumulants of this discrete PDF of load.

Step 3: Select the commitment schedule on a priority basis dictated by unit average incremental cost. Define the PDF of outage capacity for each unit. A multistate PDF of outage capacity and multiblock loading can be easily incorporated.

Step 4: Obtain the cumulants of the RV corresponding to unit capacity on outage. Add these cumulants to those of demand and obtain the cumulants of a PDF of equivalent load.

Step 5: Obtain the expected unserved energy before and after the unit is committed. Their difference is the expected energy produced by the unit. Multiplying by the average incremental cost gives the production cost. For multiblock loading, the average incremental cost for the block must be used (see e.g. Ref. [2]). For limited energy units see Ref. [13]. For this case, however, care must be exercised in deconvolving lower order blocks before upper blocks are convolved.

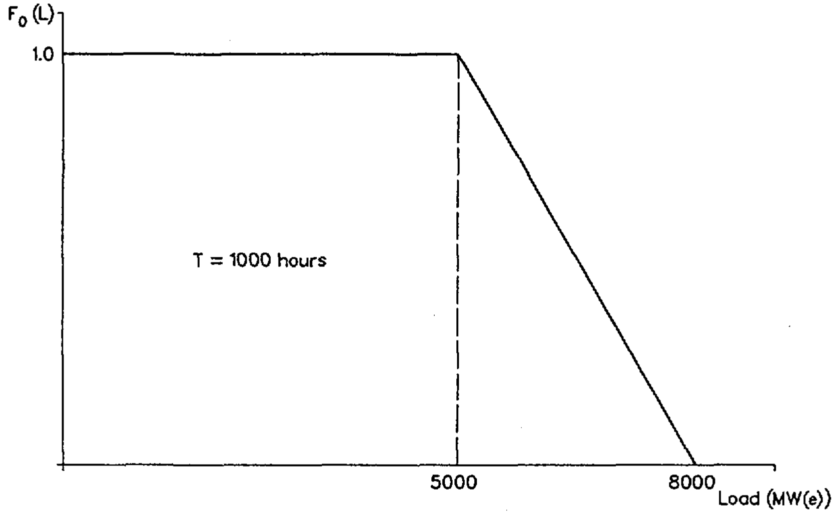

FIG.C.1. Load distribution for hypothetical system.

C.2.4. Sample problem for cumulant method

The LDC is assumed to be given and hence Variation 2 is described below. The system analysed has an installed capacity of 10 000 MW, with 100 MW units each with an FOR = 0.1. The incremental cost for all units is taken to be US \$10/MW·h at full load conditions. The units are segmented into capacity blocks and loaded to full capacity when committed. The initial LDC is shown in Fig.C.1 (this curve is sometimes called the inverted load duration curve).

The PDF of outage capacity for each unit is represented in Fig.C.2. The unit is available with 100 MW capacity 90% of the time and unavailable 10% of the time.

Table C.I. shows the normalized moments and corresponding cumulants for the LDC. These normalized moments and cumulants are obtained from a normalized LDC whose area is unity. This is necessary for evaluation of the cumulants. The area under Fig.C.1 is the initial unserved energy and equal to 5000 + 3000/2 = 6500 GW·h, considering a time period of T = 1000 hours.

Evaluation of the expected demand and energies of the first 50 units, with an installed capacity of 5000 MW, is straightforward and obtained directly from the LDC. Each unit generates $(1000 \times 0.9 \times 100) \times 10^{-3} = 90$ GW·h. The production cost for each of the first 50 units committed is thus $90 \times 10 \times 10^{-3}$ = US \$$0.9 \times 10^6$.

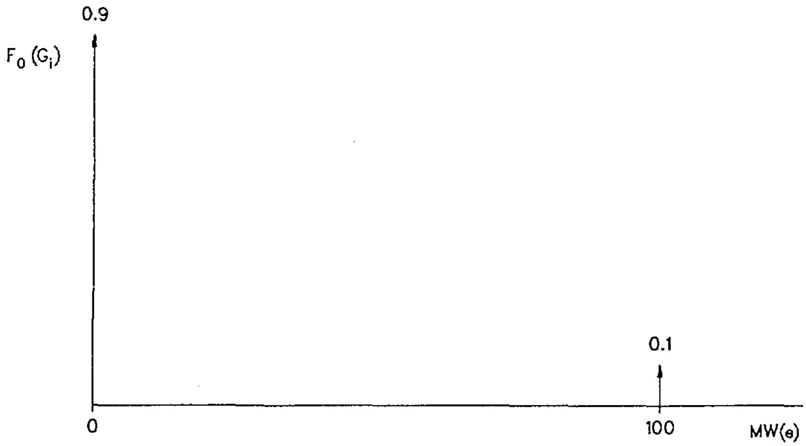

FIG.C.2. PDF of outage capacity for a unit G_i.

TABLE C.1. NORMALIZED MOMENTS AND CUMULANTS OF THE LDC OF FIG.1

Order	Moments	Cumulants
1	3.3076923×10^{3}	3.3076923×10^{3}
2	1.4833333×10^{7}	3.8925049×10^{6}
3	7.6007692×10^{10}	1.1931724×10^{9}
4	4.2140000×10^{14}	$-1.5066472 \times 10^{13}$
5	2.4652344×10^{18}	$-1.8919725 \times 10^{16}$
6	1.5006036×10^{22}	2.9115091×10^{20}
7	9.4205558×10^{25}	7.8730863×10^{23}
8	6.0625424×10^{29}	$-1.2372465 \times 10^{28}$

The Gram-Charlier expansion is used to evaluate the expected energy and production cost of the 51st unit. The first eight cumulants for any unit and for the first 50 units are shown in Table C.II. Since all the units are identical, cumulants for the first 50 units are evaluated by multiplying those for one unit by 50.

The G_ν factors for the LDC ($F_0(L)$), for the ELDC with 50 units committed ($F_{50}(L)$), and for the ELDC with 51 units committed ($F_{51}(L)$), are shown in

TABLE C.II. CUMULANTS FOR ANY UNIT AND FOR THE FIRST 50 UNITS

Order	One unit	50 units
1	10	500
2	900	4.5×10^4
3	7.2×10^4	3.6×10^6
4	4.14×10^6	2.07×10^8
5	-5.76×10^7	-2.88×10^9
6	-6.332×10^{10}	-3.276×10^{12}
7	-1.06848×10^{13}	-5.3424×10^{14}
8	-3.65544×10^{14}	-1.82772×10^{16}

Table C.III. Note the large values for the factors G_ν. For a system with PDF of outage capacity or equivalent load approaching that of a normal distribution, G_ν are relatively smaller and the Gram-Charlier or Edgeworth expansion will then give better results. For a normal distribution, all the G_ν, $\nu = 3, 4, \ldots$, factors are zero. The expected unserved energy before the convolution of the 51st unit is:

$$UE_{50} = 6500 \int_{5000}^{\infty} F_{50}(L)\, dL = 2030.872285 \text{ GW}\cdot\text{h}$$

The expected unserved energy after the convolution of the 51st unit is:

$$UE_{51} = 6500 \int_{5100}^{\infty} F_{51}(L)\, dL = 1943.976815 \text{ GW}\cdot\text{h}$$

The difference of unserved energies before and after commitment of the 51st unit is the expected energy met by Unit 51. Thus,

$$E_{51} = (UE_{50} - UE_{51}) = 86.895470 \text{ GW}\cdot\text{h}$$

TABLE C.III. FACTORS G_ν FOR THE GRAM-CHARLIER EXPANSION

Order	$F_0(L)$	$F_{50}(L)$	$F_{51}(L)$
1	0.1553672	0.1531722	0.1531239
2	−0.9943819	−0.9717698	−0.9713254
3	−0.6329099	−0.6149816	−0.6146303
4	4.9366306	4.7693019	4.7660330
5	6.7661700	6.4993679	6.4941711
6	−53.8938947	−51.4720902	−51.4250570

The production cost is thus:

$$PC_{51} = 10 \times 86.895470 \times 10^3 = \text{US } \$0.8689 \times 10^6$$

Note that the expected energy generated by Unit 51 may also be obtained from $F_{50}(L)$ as follows:

$$E_{51} = (0.9) \times (6500) \int_{5000}^{5100} F_{50}(L)\, dL = 86.896965 \text{ GW·h}$$

The slight difference is accounted for by the difference in evaluation procedure.

For scoping studies, the expected energy generation for a combination of units is usually desired. The method lends itself to unit aggregation quite effectively. As an example, assume that the expected energy generation for the combination of Units 52 to 60 is wanted. The aggregate of the cumulants corresponding to Units 52 to 60 is added to the cumulants corresponding to F_{51} to give F_{60} directly. The expected unserved energy after the commitment of the 60 units is:

$$UE_{60} = 6500 \int_{6000}^{\infty} F_{60}(L)dL = 1154.903010 \text{ GW·h}$$

The combined generation of Units 52 to 60 is therefore

$$E_{52-60} = 1943.97682 - 1154.90301 = 789.07381 \text{ GW·h}$$

C.3. THE SEGMENTATION METHOD

This method is described in Refs [14] and [15]. It is based on the observation that the LOLP and expected energy generation may be evaluated from the zeroth and first order moments of the RV describing the equivalent load. The method is not based on a series expansion but, rather, on segmentation of the hourly load into segments of equal capacity. This capacity segment is equal to the capacity of the smallest unit and/or the largest common factor of capacity of all units. For dissimilar unit sizes, a segment size of 1 MW may be considered with a corresponding increase in computational effort. The method avoids the inherent errors present in the cumulant method but obtains the result with comparable computational efficiency. For the system tested, the method gave very accurate results, comparable to those obtained by the Booth-Baleriaux method [16]. Although the method has only been tested for a few systems, the trustworthiness of the method lies in its simplicity and straightforward approach. A brief description of the two methods follows, with a comparison of results applied to the IEEE Reliability Test System (RTS) [17].

C.3.1. Basic procedure

The starting point for this method is the daily chronological load curve for a period as well as the loading order based on the average incremental cost. The segment size must also be defined. The method is fully described below with a simple example.

Consider the daily hourly load for a system (typical winter day of the IEEE RTS) as shown in Fig.C.3 (disregard at present the right-hand boxes). The generation system is described in Table C.IV.

Before the segmentation method is described, and for clarity, consider a 'brute force' method in what follows. By assigning to each sampled hour of Fig.C.3 equal probability (e.g. 1/24 in this case), a PDF of load is obtained as shown in Fig.C.4. As can be seen from Fig.C.3, there are two joint occurrences of the 29 MW load and it is therefore assigned a probability of 2/24. Equivalently, one can say that the load level of 29 MW lasted for two hours over a 24 hour period. Continuing in a similar manner, all the probabilities for each impulse of Fig.C.4 are defined.

The initial expected unserved energy per unit time[2] is equal to the first moment of the PDF of Fig.C.4. This is easily calculated as

$$UD_0 = (2 \times 29 + 2 \times 31 + \ldots + 1 \times 81)/24 = 1429/24 \text{ MW}\cdot\text{h/h}$$

[2] The term 'unserved energy per unit time' is equivalent to the term 'unserved load', sometimes used in the literature. This comes about because the PDF of Fig.C.4 may be viewed as a PDF of unserved load or power demand.

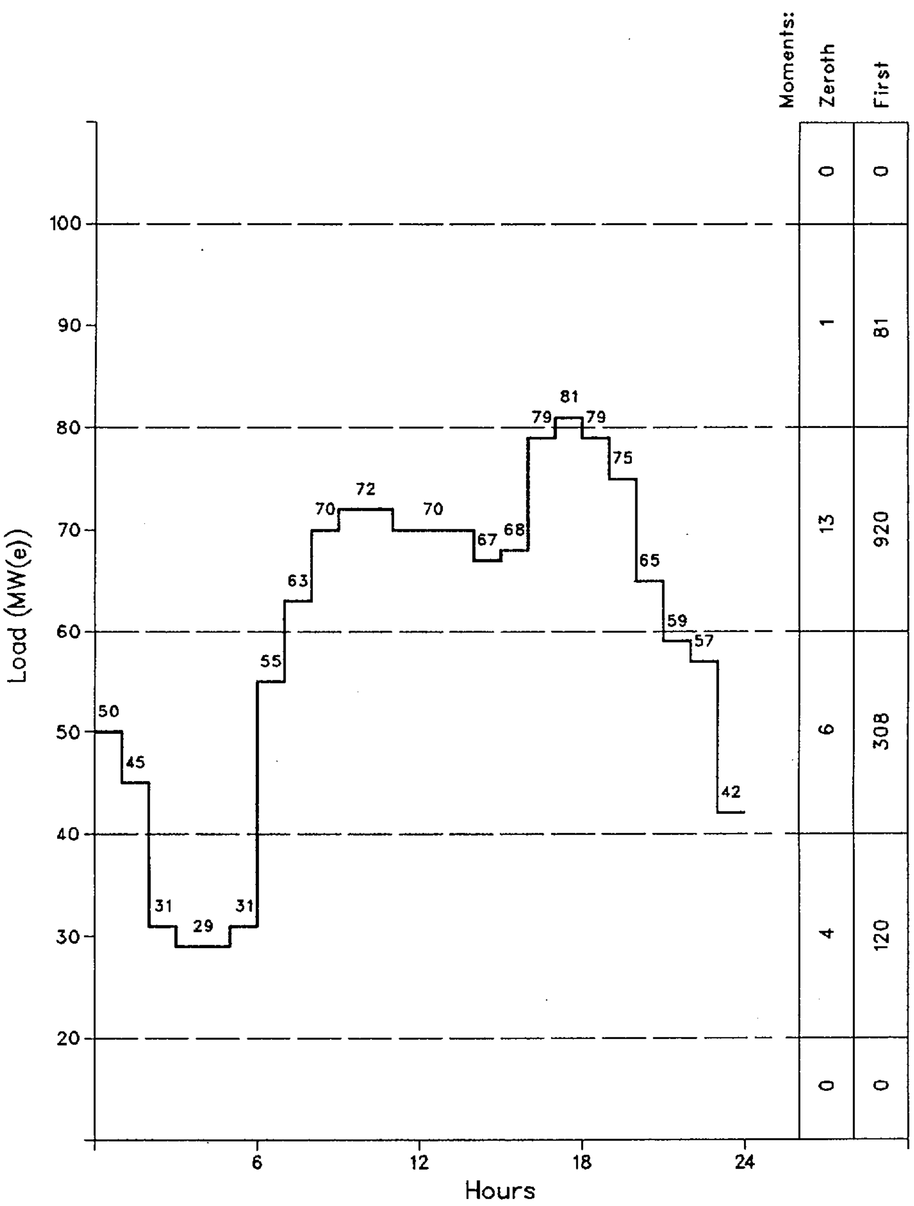

FIG.C.3. Daily hourly load profile (numbers in boxes to be divided by 24).

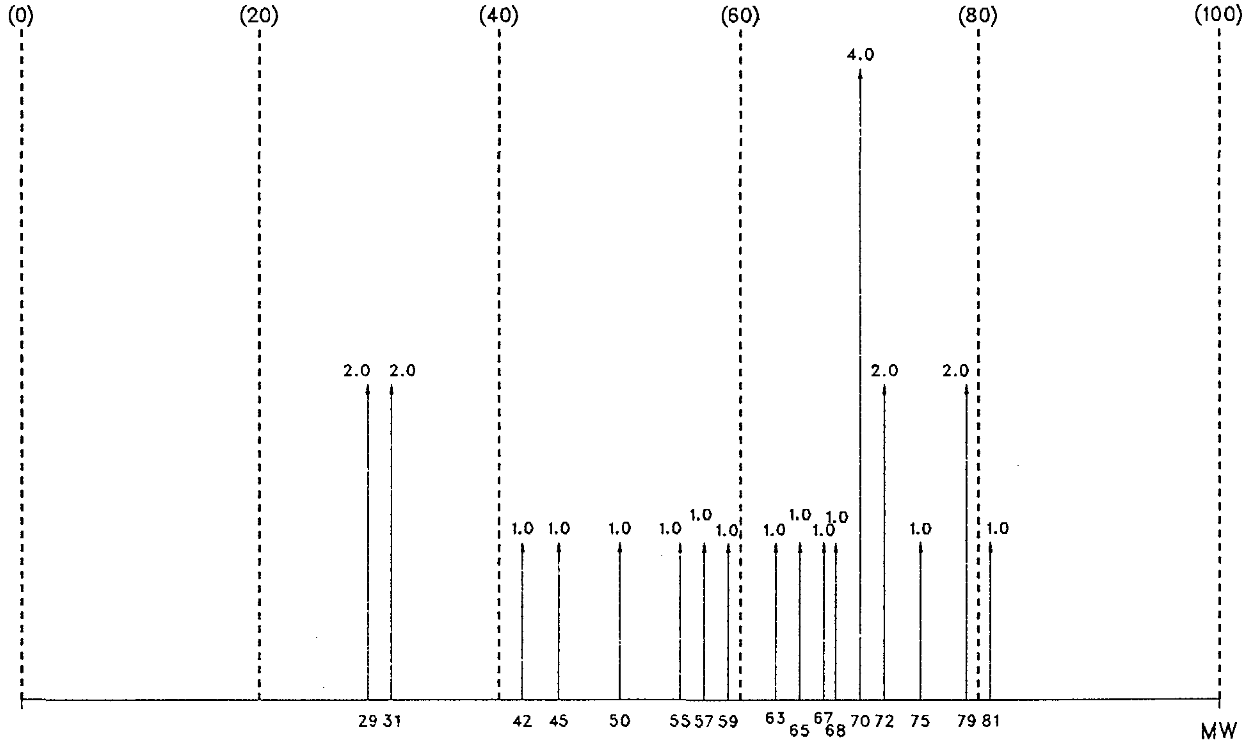

FIG.C.4. PDF of load (all impulses to be divided by 24).

TABLE C.IV. GENERATION SYSTEM DESCRIBED FOR SAMPLE SYSTEM

Unit	Capacity (MW)	FOR (%)	Utilization
1	20	10	Base
2	40	15	Intermediate
3	40	20	Peaking

For 24 hours the expected unserved energy is thus

$$UE_0 = 24 \times 1429/24 = 1429 \text{ MW}\cdot\text{h}$$

which is the total system energy demand.

Loading Unit 1 of capacity 20 MW and FOR = 0.1, the first unit in the loading order, gives rise to a PDF of equivalent load as shown in Fig.C.5. The impulses have practically doubled after the convolution process, as shown by Fig.C.5. By subtracting 20 MW (the capacity of Unit 1) from all load levels of Fig.C.5, the unserved energy per unit time after convolution of Unit 1 is:

$$UD_1 = [1.8(29-20) + 1.8(31-20) + \ldots + 0.1\,(101-20)]/24$$

$$= 997/24 \text{ MW}\cdot\text{h/h}$$

The expected unserved energy after convolution of Unit 1 is therefore:

$$UE_1 = 24 \times 997/24 = 997 \text{ MW}\cdot\text{h}$$

The expected energy generation of Unit 1 is the difference between unserved energies before and after convolution; thus:

$$E_1 = UE_0 - UE_1 = 1429 - 997 = 432 \text{ MW}\cdot\text{h}$$

The energy E_1 can also be calculated as $20 \times 24 \times 0.9 = 432$ MW·h since Unit 1 is operating at base load.

Similarly, the rest of the units are convoluted and the unserved energies and expected unit generation obtained. Impulses below committed capacity are not needed to evaluate the unserved energies, and it is not necessary to keep track of these impulses. Consequently, the number of impulses may be reduced at each stage of the convolution process, as will become clearer later.

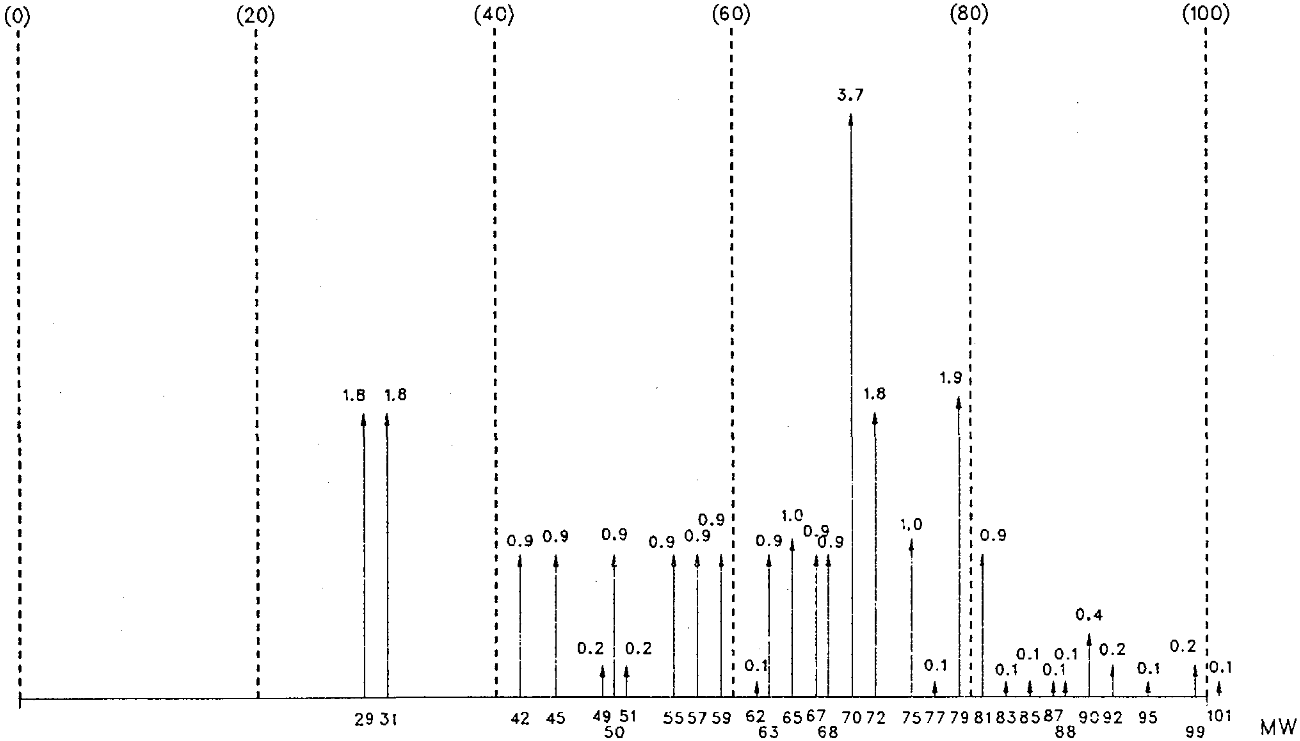

FIG.C.5. PDF of equivalent load after loading 20 MW unit (all impulses to be divided by 24).

To calculate the LOLP, all impulses lying to the right of installed capacity are needed. In Fig.C.5, with only the 20 MW unit committed, the LOLP is given by:

$$\text{LOLP} = (1.8 + 1.8 + \ldots + 0.1)/24 = 24/24 = 1$$

as it must be since the first unit of 20 MW is less than the base load (in this sample system). When all units are committed, the system LOLP is obtained in a similar manner.

The application of the 'brute force' method of convolution, described above, 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 $N \times 2^M$
A technique of convolution is described below which avoids an excessive increase in the number of impulses. This method is based on the knowledge of the zeroth and first order moments of the PDF equivalent load (or unserved load depending on the point of view).

An important step in applying the segmentation method is the selection of the segment size. This should be equal to the maximum common factor of capacity or capacity blocks (for multiblock loading) of all units. In the example 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 illustrated in Figs C.3 and C.4; as each hourly load is sampled, the zeroth and first order moments are added in the appropriate boxes. In this way the load does not have to be ordered as in Fig.C.4.

In the computer algorithm, all segments lying below base load need not be carried since the corresponding zeroth and first order moments are zero. Similarly, only one segment need be carried after installed capacity. This last segment carries the most important information since it corresponds to those equivalent load points which are not met by the installed capacity of the system.

As each unit is committed, the process of convolution demands that the PDF of load be shifted by the unit capacity and multiplied by the unit FOR. The final PDF of equivalent load is obtained by summing to this shifted PDF the original PDF multiplied by unit availability.

The segmentation method does this shifting by modifying the moments in each segment. It is well known that when PDFs are shifted the zeroth order moment remains unchanged but the first order moment is modified. Thus, for segment k:

$$m_0^{new}(k) = m_0^{old}(k) \tag{C.14}$$

$$m_1^{new}(k) = m_1^{old}(k) + shift \times m_0^{old}(k) \tag{C.15}$$

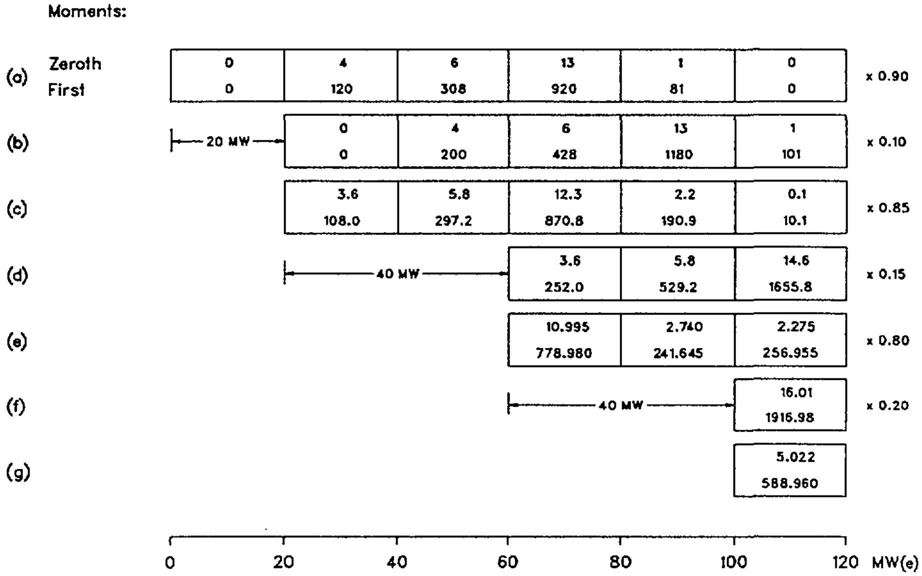

FIG.C.6. Schematic of evaluation procedure (all numbers in boxes to be divided by 24).

where

$m_0^{new}(k)$ is the shifted zeroth moment[3] in segment k

$m_1^{new}(k)$ is the shifted first moment in segment k

$m_1^{old}(k)$ is the original first moment in segment k

$m_0^{old}(k)$ is the original zeroth moment in segment k

Consider Fig.C.6(a), which depicts schematically the zeroth and first order moments of the load of Fig.C.3. Six segments have been considered: one above installed capacity, four between installed capacity and base load, and another below base load. The 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, thus saving computer storage. The segment above installed capacity contains the values for the evaluation of LOLP and expected unserved energy, as will become clearer later.

[3] The zeroth order moment of a segment may also be thought of as the segment's probability.

Still considering Fig.C.6(a), note that the zeroth and first order moments are obtained in a straightforward way. For instance, for the fourth segment, these two moments are (from Fig.C.4 or Fig.C.3) given by:

$$m_0 = (1 + 1 + 1 + 1 + 4 + 2 + 1 + 2)/24 = 13/24$$

$$m_1 = (63 \times 1 + 65 \times 1 + \ldots + 79 \times 2)/24 = 920/24$$

Consider now Fig.C.6(b), which shows the effect of committing the 20 MW unit. The shifted moments are obtained from Eqs (C.14) and (C.15). For the second shifted segment in Fig.6 (b) these moments are:

$$m_0 = 4/24$$

$$m_1 = 120/24 + 20 \times 4/24 = 200/24$$

The two moments for all other segments in Fig.C.6 (b) are obtained similarly. Note that only one composite segment is carried past 100 MW, the installed capacity of the system. The sum of all segments past installed is placed in this composite segment.

Figure C.6(c) is obtained by multiplying each moment in each segment of Fig.C.6 (a) by the availability of the unit, p = 0.9, and each moment in each segment of Fig.C.6 (b) by the FOR of the unit, FOR = 0.1, and summing the corresponding segments.

Recalling the procedure for evaluating the unserved energy, one is interested in the zeroth and first order moments of the PDF of equivalent load lying to the right of committed capacity. It is therefore not necessary to know the moments of the individual segments to the left of committed capacity, as shown in Fig.C.6 (c). However, this is only true when unit deconvolution is not contemplated. as will become clearer later.

A general expression for expected unserved energy per unit time may be written as

$$UD_{CU} = \sum_{j=s}^{NS} m_1 - \left(\sum_{j=1}^{CU} C_j\right)\left(\sum_{j=s}^{NS} m_0\right) \tag{C.16}$$

where NS is the total number of segments, CU is the total number of committed generating units, and s is the number of committed segments corresponding to a generating unit. The unserved energy is thus

$$UE_{CU} = T \times UD_{CU} \tag{C.17}$$

From Fig.C.6(a), the initial expected unserved energy per unit time is:

$$UD_0 = \sum_{j=1}^{6} m_1 = (0 + 120 + 308 + 920 + 81 + 0)/24 = 1429/24\ \text{MW}\cdot\text{h}/\text{h}$$

Thus

$$UE_0 = 1429\ \text{MW}\cdot\text{h}$$

The unserved energy per unit time after committing the 20 MW unit with FOR = 0.1 is, from Fig.C.6(c), equal to:

$$UD_1 = \sum_{j=2}^{6} m_1 - \left(\sum_{j=1}^{1} C_j\right)\left(\sum_{j=2}^{6} m_0\right)$$

$$= (108 + 297.2 + 870.8 + 190.9 + 10.1)/24$$

$$- (20)\,(3.6 + 5.8 + 12.3 + 2.2 + 0.1)/24 = 997/24\ \text{MW}\cdot\text{h}/\text{h}$$

Thus

$$UE_1 = 997\ \text{MW}\cdot\text{h}$$

A general expression for the expected unit energy generation is

$$E_{CU} = T(UD_{CU-1} - UD_{CU}) \tag{C.18}$$

The expected energy generation of Unit 1 is thus:

$$E_1 = T(UD_0 - UD_1) = 24(1429 - 997)/24 = 432\ \text{MW}\cdot\text{h}$$

or, equivalently,

$$E_1 = UE_0 - UE_1 = 1429 - 997 = 432\ \text{MW}\cdot\text{h}$$

Unit 2 is committed next. This unit has a capacity $C_2 = 40$ MW and FOR = 0.15. Figure C.6(d) is obtained from Fig.C.6(c) by shifting the segments by 40 MW. Thus for the first shifted segment in Fig.C.6(d) one obtains:

$$m_0^{new} = 3.6/24$$

$$m_1^{new} = (108 + 40 \times 3.6)/24 = 252/24$$

The last shifted segment in Fig.C.6(d) combines the last three segments of Fig.C.6(c). Figure C.6(e) is obtained by multiplying all moments in each segment of Fig.C.6(c) by p = 0.85 and those of Fig.C.6(d) by FOR = 0.15. The segments below 60 MW of committed capacity are not retained since they are not required.

The expected energy per unit time after convoluting the second units is, from Fig.C.6(e) and Eq.(C.16), given by

$$UD_2 = \sum_{j=4}^{6} m_1 - \left(\sum_{j=1}^{2} C_j\right)\left(\sum_{j=4}^{6} m_0\right)$$

$$= (777.98 + 241.645 + 256.955)/24$$

$$-\,(20 + 40)\,(10.995 + 2.740 + 2.275)/24$$

$$= 315.980/24 \text{ MW}\cdot\text{h}/\text{h}$$

Thus

$$UE_2 = 315.980 \text{ MW}\cdot\text{h}$$

The expected energy generation of Unit 2 is thus:

$$E_2 = T(UD_1 - UD_2) = 24(997 - 315.98)/24$$

$$E_2 = 681.020 \text{ MW}\cdot\text{h}$$

or, equivalently,

$$E_2 = UE_1 - UE_2 = 997 - 315.98 = 681.020 \text{ MW}\cdot\text{h}$$

The last unit to be committed is a 40 MW unit with FOR = 0.2. Figure C.6(f) shows the effect of shifting the segments of Fig.C.6(c) by 40 MW. The only segment produced combines the three last segments of Fig.C.6(e). Multiplying all moments in all the segments of Fig.C.6(e) by p = 0.80 and those in Fig.C.6(f) by FOR = 0.2 and adding corresponding segments produces Fig.C.6(g).

The expected unserved energy per unit time after committing this last unit is:

$$UD_3 = \sum_{j=6}^{6} m_1 - \left(\sum_{j=1}^{3} C_j\right)\left(\sum_{j=6}^{6} m_0\right)$$

$$= 588.96/24 - (20 + 40 + 40)\,(5.022)/24$$

$$= 86.760/24 \text{ MW}\cdot\text{h}/\text{h}$$

Thus

$$UE_3 = 86.760 \text{ MW}\cdot\text{h}$$

The expected energy generation of Unit 3 is thus:

$$E_3 = T(UD_2 - UD_3) = 24(315.980 - 86.760)/24$$

$$E_3 = 229.220 \text{ MW}\cdot\text{h}$$

or, equivalently,

$$E_3 = UE_2 - UE_3 = 315.980 - 86.760 = 229.220 \text{ MW}\cdot\text{h}$$

The total expected energy generation is thus

$$E_T = E_1 + E_2 + E_3 = 1342.240 \text{ MW}\cdot\text{h}$$

The energy balance (EB) is

$$EB = 1429 - (1342.240 + 86.760) = 0 \text{ MW}\cdot\text{h}$$

in which 1429 MW·h correspond to the system's total energy demand.

The system LOLP is simply the zeroth moment in Fig.C.6(g) lying after installed capacity. Thus

$$\text{LOLP} = 5.022/24 = 0.20925$$

In the computer algorithm the period T, 24 hours in this case, is not carried through in order to avoid computer round-off errors. It is emphasized that the LOLP and expected energies evaluated are exact for the sampling interval considered. A detailed analysis of this simple system will give the same answers.

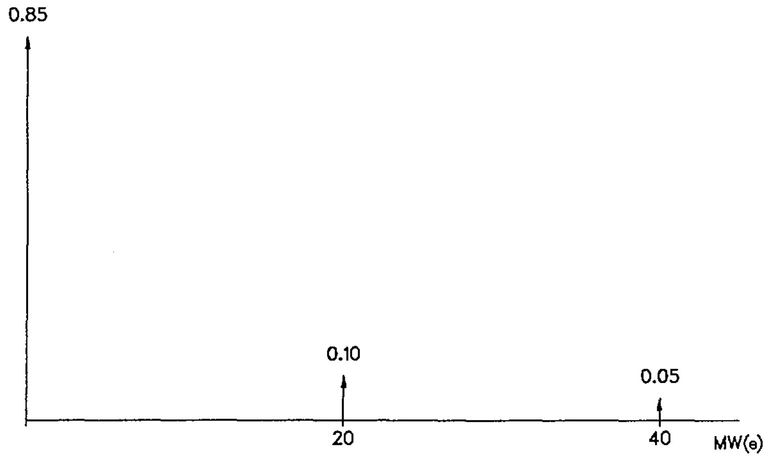

FIG.C.7. Three-state representation of a unit.

One comment about obtaining Fig.C.6(a) from the chronological load curve. The zeroth and first order moments in each segment of Fig.C.6(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. An hourly sample is used in this example; for a more accurate load representation the load curve may be sampled at a shorter time interval.

A multistate representation for a generating unit is easily taken into account. Consider a three-state model for the capacity on outage of a unit as shown in Fig.C.7. The unit is available at full capacity for 85% of the time, derated by 20 MW for 10% of the time, and failed for 5% of the time. Figure C.8 shows schematically the procedure for shifting the segments, assuming that the three-state unit is committed after committing the first unit in Fig.C.6. As discussed, the segments must be shifted by the appropriate amount and the zeroth and first order moments modified accordingly. In Fig.C.8 the same average incremental cost has been assumed for each block of capacity for the three-state unit.

Unit aggregation may be considered for scoping studies in order to increase the segment size and decrease the number of segments, thus increasing the computational efficiency. The result of unit aggregation will be a multistate model (an equivalent two-state representation may also be considered). Implicit in this is an equal average incremental cost for each unit to be aggregated.

C.3.2. Multiblock loading for generating units

To better simulate the economic dispatch procedure, a useful stratagem is to load the units in capacity blocks each of which may have a different average

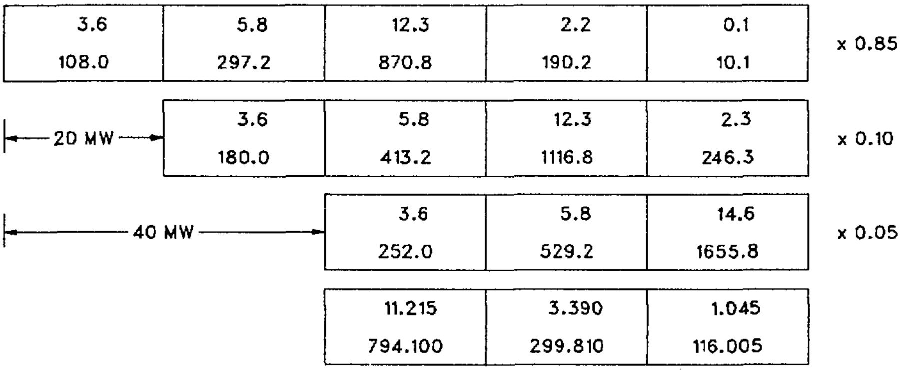

FIG.C.8. Convolution of multistate unit (all numbers in boxes to be divided by 24).

incremental cost. Clearly the capacity blocks may occupy non-adjacent positions in the loading order of merit. The basic consideration in the simulation procedure of multiblock loading is that higher order blocks cannot be loaded until lower blocks have been committed. To account correctly for this dependence, lower order blocks must first be deconvolved before the combined lower and higher blocks are convolved. As explained by Zahavi [18], 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:

$$f_z(x) = p_i f_y(x) + q_i f_y(x - C_i) \qquad \text{(C.19)}$$

where

$f_y(x)$ is the PDF of equivalent load prior to loading unit or block of capacity C_i,
$f_z(x)$ is the PDF of equivalent load after loading unit or block of capacity C_i,
p_i is the availability of unit or block i,

$q_i = 1-p_i$

For deconvolution of a unit or block of capacity C_i and a system with an installed capacity IC, Eq. (C.19) must be used as follows:

$$f_y(x) = \begin{cases} f_z(x)/p_i & 0 \leqslant x \leqslant C_i \\ (f_z(x) - q_i\, f_y(x-C_i))/p_i & C_i < x \leqslant IC \\ \text{subtraction from total moments} & IC < x \end{cases} \tag{C.20}$$

To simulated deconvolution by segmentation, all segments above base load must be carried through. In Fig.C.6(e) the first, second and third segments have not been carried through since they are not needed in standard convolution. However, for deconvôlution these segments must be carried through. In any case, all segments below base load need not be carried through in the computational procedure since their moments are zero. The procedure for deconvolution is clarified in what follows.

Consider Fig.C.6(c), which shows all the required segments for deconvolution. What is wanted is to deconvolute the 20 MW unit or block with FOR = 0.1 to obtain Fig.C.6(a). The procedure is explained below for each segment of Fig.C.6(a):

1st segment (0 to 20 MW)

This segment lies below base load and hence its moments are zero. Thus:

$m_0 = 0$

$m_1 = 0$

2nd segment (20 MW to 40 MW)

$m_0 = ((3.6 - 0.1 \times 0.0)/0.9)/24 = 4.0/24$

$m_1 = ((108.0 - 1 \times 0.0)/0.9)/24 = 120/24$

3rd segment (40 MW to 60 MW)

$m_0 = ((5.8 - 0.1 \times 4)/0.9)/24 = 6.0/24$

$m_1 = ((297.2 - 0.1 \times (120 + 20 \times 4))/0.9)/24 = 308/24$

4th segment (60 MW to 80 MW)

$m_0 = ((12.3 - 0.1 \times 6)/0.9)/24 = 13/24$

$m_1 = ((870.8 - 0.1 \times (308 + 20 \times 6))/0.9)/24 = 920/24$

5th segment (80 MW to 100 MW)

$$m_0 = ((2.2 - 0.1 \times 13)/0.9)/24 = 1/24$$

$$m_1 = ((190.9 - 0.1 \times (920 + 20 \times 13))/0.9)/24 = 81/24$$

6th segment (100 MW to 120 MW)

This last segment is special and must be calculated from the knowledge of the sum total of the zeroth and first order moments of Fig.C.6(a). These moments are known, however. The sum of the first moments in Fig.C.6(c) is $m_1 = 1477/24$. The first moment of capacity outage of the 20 MW unit is $20 \times 0.1 = 2.0 = 48/24$. Thus, the sum of the first moments of Fig.C.6(a) is $(1477 - 48)/24 = 1429/24$. The sum of the zeroth order moments is always 1. Thus, the moments of the sixth segment are:

$$m_0 = (24 - (0 + 4 + 6 + 13 + 1))/24 = 0$$

$$m_1 = (1429 - (0 + 120 + 308 + 920 + 81))/24 = 0$$

C.3.3. Guidelines for selecting the segment size

The segment size should be equal to the maximum common factor of capacity of all the units or capacity blocks (for multiblock loading) in the system. Clearly, if all the units are dissimilar, the segment size must be 1 MW (fractional unit sizes may be considered but are not recommended). Reducing the segment size increases the number of segments spanning the installed capacity, with a corresponding increase in the computational requirements. However, as shown in Section C.4, this increase is quite acceptable. Similarly, a coarse segment size may be used, although the results obtained can be only approximate; the coarser the segment size the more inaccurate the results.

If all the units are dissimilar, one possible approach is to round off some of the unit capacities. For instance, a 197 MW unit may be considered as a 200 MW unit. Another stratagem is to round off the unit capacities and, in addition, modify the corresponding FORs so that the product of capacity and FOR remains unchanged (equality of the first moments of outage capacity).

C.4. NUMERICAL COMPARISON OF TECHNIQUES

The results of the two techniques and those obtained from the often-used Booth-Baleriaux method [16, 19] are described below for a realistic system. Table C.V

TABLE C.V. GENERATION DATA FOR SAMPLE SYSTEM

Type of unit	Unit size (MW)	No. of units	FOR	Ave. λ (US \$/MW·h)
Nuclear	400	2	0.12	5.45
Coal	350	1	0.08	10.883
Coal	150 (155)[a]	4	0.04	10.704
Coal	80 (76)	4	0.02	13.494
Oil	200 (197)	3	0.05	20.730
Oil	100	3	0.04	20.853
Oil	20	4	0.10	25.875
Oil	10 (12)	5	0.02	37.500
Hydroelectric	50	6	0.01	0
Total	3400 (3405)	32		

[a] Actual capacities.

describes the generation system. The generation data of this table correspond to the IEEE RTS [17], but have some units with rounded-off capacities. (The actual capacities for the IEEE RTS are given in parentheses in Table C.V.) For the rounded-off system a 10 MW segment may be used (only the capacities have been altered in the modified system).

The load is described in Ref. [17]. It corresponds to weeks 1–8 and 48–52 with a peak load of 2850 MW and a minimum load of 1102 MW. The time period is 2184 hours.

The generation model consists of 32 units, including six hydroelectric generators of 50 MW capacity each. The dependable energy for each hydraulic unit is limited to 40 GW·h 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 4163.480402 GW·h. The loads have been sampled every hour.

The expected generated energy, unserved energy and production costs for this method are shown in Table C.VI. The loading order as specified in this table is obtained from the average incremental costs as shown in Table C.V. In Table C.VI, the third and fifth columns correspond to the expected energies and fuel costs obtained from the commonly used Booth-Baleriaux method with a capacity increment of 10 MW. The capacity of the smallest unit(s) is 10 MW, which is the maximum common factor for all generating units, and a segment of 10 MW is therefore utilized. The cumulant method uses eight cumulants in the Gram-Charlier expansion.

TABLE C.VI. COMPARISON OF EXPECTED ENERGIES AND PRODUCTION COSTS FOR EACH UNIT

Unit No.	Capacity (MW)	Expected energy generation (GW·h)			Production costs (US $\$10^6$)		
		Booth-Baleriaux method	Segmentation method	Cumulant method	Booth-Baleriaux method	Segmentation method	Cumulant method
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	118.490	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	97.278	1.30362	1.30366	1.31942
11	80	89.029	89.031	85.675	1.20136	1.20139	1.15609
12	200	98.889	98.889	85.525[a]	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

[a] The order of the 200 MW coal fuel unit and the hydroelectric unit are inverted in the cumulant method. Refer to Ref.[13] for a detailed explanation of production costing with energy limited units such as hydroelectric units.

TABLE C.VII. COMPARISON OF RESULTS OF TABLE C.VI

	Booth-Baleriaux method	Segmentation method	Cumulant method
Expected energy (GW·h)	4162.61740	4162.65315	4162.69562
Unserved energy (GW·h)	0.82670	0.82725	0.40706
Energy balance (GW·h)	0.03603	0	0.37772
System LOLP (%)	0.2886	0.2886	0.2395
CPU time[a] (s)	3.1	0.3	0.28

[a] IBM 3033 Computer.

TABLE VIII. COMPARISON OF RESULTS FOR IEEE RTS FOR TWO SEGMENT SIZES

Segment size (MW)	1	10
Expected energy (GW·h)	4162.682614	4162.810715
Unserved energy (GW·h)	0.798085	0.669985
Energy balance (GW·h)	0	0
Fuel cost (US $)	36813992	36806966
LOLP (%)	0.275144	0.277173
CPU (s)	0.56	0.30

For the Booth-Baleriaux method, decreasing the size of the capacity increment does not improve the solution because of round-off errors. The computational efficiency and accuracy of the segmentation method are clear, as Table C.VII shows. The CPU time for the segmentation method for a segment size of 1 MW was 0.56 seconds, with exactly the same results as those shown in Table C.VI. A segment size of 1 MW will cover all possible capacity states and is required with disparate unit sizes.

The hydroelectric units are discharging 240 GW·h during the selected period. Unit 12, being oil-fired, must therefore be off-loaded to accommodate these units for both the Booth-Baleriaux and the segmentation methods. In the cumulant method the 240 GW·h hydroelectric units off-load Unit 11, a coal-fired unit.

For comparison as well as for completeness, the actual IEEE RTS generation data were used in order to obtain the results shown in Table C.VIII. For this system, with an installed capacity of 3405 MW and dissimilar units, a 1 MW segment size was used. Table C.VIII also shows the results obtained for a coarse segment size of 10 MW.

Note that the computational requirements have almost doubled for a 1 MW segment size. However, the results obtained for the coarse 10 MW segment size are quite reasonable. The expected energy generation for the 1 MW coarse segment size differs by about 0.003%. The expected energies for each unit differ by less than 0.1%. A segment size greater than 10 MW does not significantly improve the CPU·time.

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Appendix D

EXAMPLES OF AUXILIARY COMPUTER MODELS FOR LONG-RANGE ELECTRICITY PLANNING

This Appendix describes some methodologies and computer models available for the analysis of constraints imposed on power system expansion planning or on the preparation of data needed to carry out such planning studies.

D.1. FINANCIAL ANALYSIS

As discussed in Section 3.2 and in Chapter 9, adequate financial analysis is required to enhance the soundness of the results of a planning study. Different levels of detail and emphasis would be exercised for planning the strategies of development for the power system in the long term and for planning studies connected with a specific project or projects. The theoretical background to pure financial analysis lies in the field of the theory of economics, which is obviously beyond the scope of this guidebook. Many computer techniques applicable to financial analysis have been developed and are used, depending on the application, so no method needs to be described. What is important is that the financial analyst should be provided with all information relevant to the analysis. Moreover, as a result of the analysis, it may be necessary to carry out further studies or to repeat previous analyses.

The following methods can help prepare this information or carry out subsequent studies resulting from the financial analysis.

D.1.1. Estimates of power plant investment cost (CONCEPT, ORCOST)

Estimates of power plant investment cost can be provided, for instance, by computer programs like CONCEPT [1] and ORCOST [2]. Both computer codes were developed by Oak Ridge National Laboratory, USA, and use the same basic methodology. There are some differences in the types of plant that can be considered and in the output provided by each program. CONCEPT and ORCOST permit calculation of cost estimates for nuclear-fuelled and fossil-fired power plants and as a function of plant size, location, construction period and date of initial operation. The results of the analysis include a detailed breakdown of the estimate into direct and indirect cost components similar to the accounting system recommended in Ref. [3]. The major cost accounts for direct and indirect costs considered by this accounting system are shown in Table D.I.

TABLE D.I. NUS MAJOR COST ACCOUNTS FOR POWER PLANT INVESTMENT COSTS

NUS account No.	Item
Direct costs:	
21	Structures and site facilities
22	Reactor/boiler plant equipment
23	Turbine plant equipment
24	Electric plant equipment
25	Miscellaneous plant equipment
26	Special material (cooling towers, SO_x removal system)
Indirect costs:	
91	Construction facilities, equipment and services
92	Home office engineering
93	Other costs (field office engineering and construction management)

Other cost items also calculated are:

Land rights (Acc. No. 20)

Owner's costs (Acc. No. 94)

Contingency allowance

Escalation during construction

Interest during construction

The main assumption of both CONCEPT and ORCOST is that, for a given type and size of power plant and irrespective of its geographical location, the sizes of individual items or equipment, the amounts of construction materials, and the number of man-hours of construction labour remain the same for each of the six major direct plant cost accounts shown in Table D.I (Acc. Nos 21–26). It is further assumed that the cost-size relationship for the direct cost accounts can be adequately described by an exponential law. Moreover, indirect costs and other cost items can be estimated by applying appropriate percentages to the physical plant costs.

The application of the approach requires a detailed cost model for each plant type at a reference condition and the determination of cost-trend relationship.

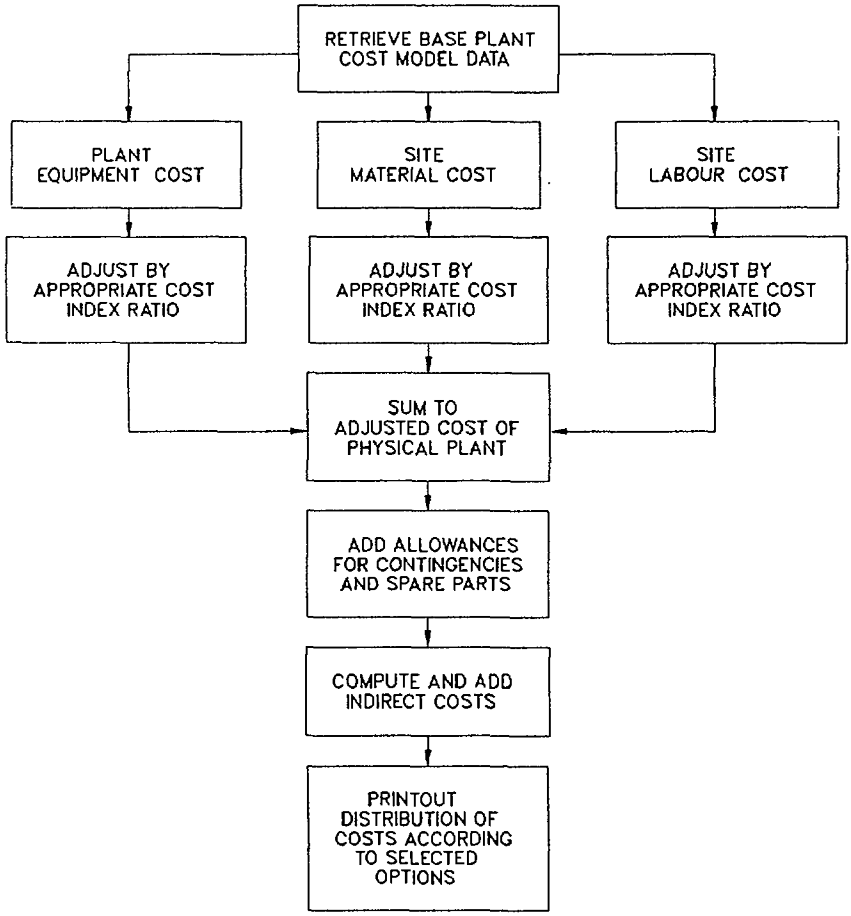
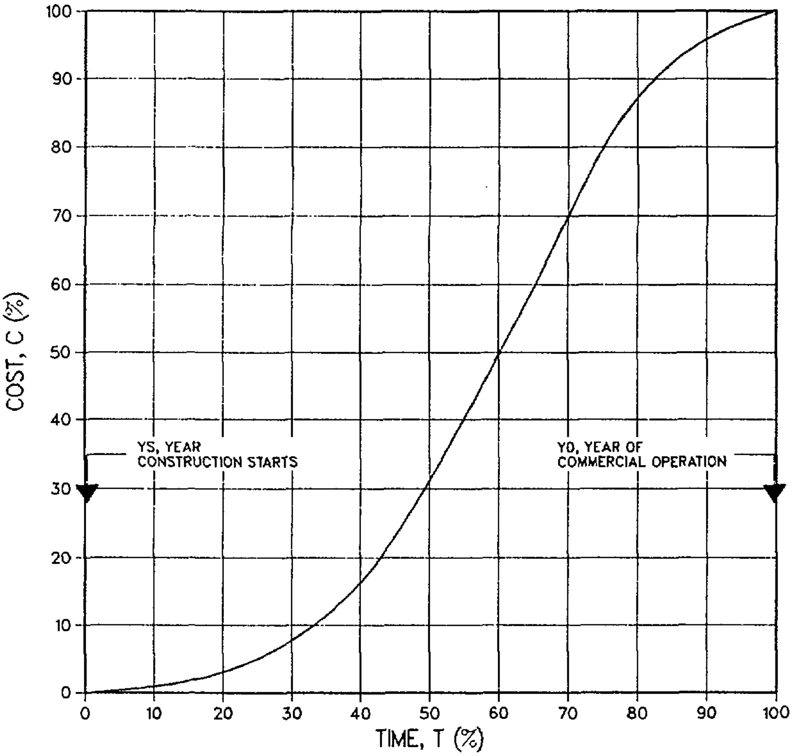


FIG.D.1. Schematic illustration of ORCOST and CONCEPT procedures.

On the basis of the above assumptions, one can adjust the costs of the base model for size and apply appropriate cost indices for equipment, material and labour. These indices reflect the conditions prevailing in the specific country and site where the plant is assumed to be built, relative to the unit costs of the base model. The indirect costs and the allowances for spare parts and contingencies are computed by applying appropriate percentages to the physical plant costs.

The above procedure is illustrated in Fig.D.1. Cost estimates produced as outlined above refer to relatively large steam electric plants and are not intended to be substitutes for detailed cost estimates of specific projects. However, ORCOST and CONCEPT estimates should be useful as a rough check of the detailed estimates or for application in power system expansion studies.



$$T = f(C) = a_0 + a_1 C + a_2 C^2 + a_3 C^3 + a_4 C^4 + a_5 C^5 + a_6 C^6 + a_7 C^7$$

where:

$a_0 =$	$+0.72954$	$a_4 =$	-7.36442×10^{-4}
$a_1 =$	$+7.17832$	$a_5 =$	$+1.00715\times10^{-5}$
$a_2 =$	-6.16794×10^{-1}	$a_6 =$	-7.02449×10^{-8}
$a_3 =$	$+2.91329\times10^{-2}$	$a_7 =$	$+1.95903\times10^{-10}$

FIG.D.2. Plant capital investment expenditures versus time in ORCOST.

The main differences between the CONCEPT and ORCOST programs can be summarized as follows:

Calculation of interest and escalation during construction (IDC and EDC) in CONCEPT and ORCOST assumes a similar distribution with time of the cost expenditures. This distribution function of cost versus time follows an S-type curve like the one shown in Fig.D.2.

For this typical cash flow curve, interest during construction can be calculated for a given construction period and a given interest rate throughout the construction period. The interest charges can be presented either in terms of a percentage of fore costs (see Table D.II) or as a percentage of total capital investment costs without the effect of inflation (see Table D.III).

One single curve is used in ORCOST for calculating IDC and EDC costs. CONCEPT requires a cash flow curve for each two-digit direct and indirect cost account, so that a set of cash flow curves is provided with each plant type base model as illustrated in Fig.D.3. Moreover, the reference cash flow curve may be modified to reflect the variations of the construction schedule for the specific case with respect to the reference conditions. The corresponding information is needed as *input data.*

The various *types of plant models* currently provided in CONCEPT correspond to pressurized-water reactors (PWR), boiling-water reactors (BWR), and coal-fired plants with and without fuel gas desulphurization equipment. In addition, ORCOST provides cost models for oil- and gas-fired power plants, and for high-temperature gas-cooled reactors (HTGR) and pressurized heavy-water reactors of the CANDU type (see Appendix B of Ref. [4]). The cost models were derived from comprehensive cost studies, most of which were performed in the USA and are updated periodically. Most of the cost models refer to US (the CANDU model refers to Canadian) regulatory requirements and economic conditions and are based on construction of the plant in a hypothetical site (Middletown) with quasi-ideal conditions. Finally, all cost models in ORCOST correspond to single-unit plants whereas single and multi-unit plant cost models can be provided by CONCEPT.

Printed outputs produced by the two programs for a given plant analysis include a cost summary output with breakdown of cost accounts at the two-digit level. CONCEPT may also be used to provide a plot of the cumulative cash flow of expenditures and also a complete cost breakdown of the cost accounts (to the three- four- and five-digit level). On the other hand, ORCOST outputs may contain summary tables with principal results for the various plant types and sizes considered in one single run of the program.

D.1.2. Cash flow analysis (CONCOS)

This computer program, described in Ref.[5], may be used to provide the flow of all direct and indirect components of capital costs arising from a determined schedule of plant additions during the study period. Construction cost, interest during construction (IDC), construction cost plus IDC, fuel investment cost and total costs may be provided, according to certain input options controlled by the user.

CONCOS is closely related to module REPROBAT of the WASP program (see Chapter 11), but it can be used independently of an electric power system planning study carried out by WASP. In this respect, CONCOS can be used

TABLE D.II. INTEREST DURING CONSTRUCTION (IDC) IN PERCENTAGE OF FORE COST

CONSTRUCTION PERIOD YEARS	INTEREST RATE										
	1.0%	1.5%	2.0%	2.5%	3.0%	3.5%	4.0%	4.5%	5.0%	5.5%	6.0%
1.0	0.42	0.64	0.85	1.06	1.27	1.49	1.70	1.91	2.13	2.34	2.56
1.5	0.64	0.96	1.28	1.60	1.92	2.24	2.56	2.89	3.21	3.54	3.87
2.0	0.85	1.28	1.71	2.14	2.57	3.00	3.44	3.87	4.31	4.75	5.20
2.5	1.06	1.60	2.14	2.68	3.22	3.77	4.32	4.87	5.43	5.98	6.54
3.0	1.28	1.92	2.57	3.22	3.88	4.54	5.21	5.88	6.55	7.23	7.91
3.5	1.49	2.25	3.01	3.77	4.55	5.32	6.11	6.90	7.69	8.50	9.30
4.0	1.71	2.57	3.45	4.33	5.22	6.11	7.02	7.93	8.85	9.78	10.72
4.5	1.92	2.90	3.89	4.88	5.89	6.91	7.93	8.97	10.02	11.08	12.15
5.0	2.14	3.23	4.33	5.44	6.57	7.71	8.86	10.03	11.21	12.40	13.61
5.5	2.36	3.56	4.77	6.01	7.25	8.52	9.80	11.09	12.41	13.74	15.09
6.0	2.57	3.89	5.22	6.57	7.94	9.34	10.74	12.17	13.63	15.10	16.59
6.5	2.79	4.22	5.67	7.14	8.64	10.16	11.70	13.27	14.86	16.47	18.11
7.0	3.01	4.55	6.12	7.72	9.34	10.99	12.67	14.37	16.11	17.87	19.66
7.5	3.23	4.89	6.58	8.30	10.05	11.83	13.64	15.49	17.37	19.28	21.23
8.0	3.45	5.23	7.03	8.88	10.76	12.68	14.63	16.62	18.65	20.72	22.83
8.5	3.67	5.56	7.49	9.46	11.48	13.53	15.63	17.77	19.95	22.18	24.46
9.0	3.89	5.90	7.95	10.05	12.20	14.39	16.63	18.92	21.26	23.66	26.10
9.5	4.11	6.24	8.42	10.65	12.93	15.26	17.65	20.09	22.60	25.16	27.78
10.0	4.33	6.58	8.88	11.24	13.66	16.14	18.68	21.28	23.95	26.68	29.48
10.5	4.56	6.92	9.35	11.84	14.40	17.02	19.71	22.48	25.31	28.22	31.21
11.0	4.78	7.27	9.82	12.45	15.15	17.92	20.76	23.69	26.70	29.79	32.96
11.5	5.00	7.61	10.30	13.06	15.90	18.82	21.82	24.92	28.10	31.38	34.75
12.0	5.23	7.96	10.77	13.67	16.65	19.73	22.90	26.16	29.52	32.99	36.56
12.5	5.45	8.31	11.25	14.29	17.42	20.65	23.98	27.42	30.96	34.62	38.40
13.0	5.68	8.66	11.73	14.91	18.19	21.57	25.07	28.69	32.42	36.28	40.27
13.5	5.90	9.01	12.21	15.53	18.96	22.51	26.18	29.97	33.90	37.96	42.17
14.0	6.13	9.36	12.70	16.16	19.74	23.45	27.29	31.28	35.40	39.67	44.10
14.5	6.36	9.71	13.19	16.79	20.53	24.41	28.42	32.59	36.92	41.41	46.06
15.0	6.59	10.07	13.68	17.43	21.32	25.37	29.56	33.93	38.46	43.16	48.06
15.5	6.81	10.42	14.17	18.07	22.12	26.34	30.72	35.28	40.02	44.95	50.08
16.0	7.04	10.78	14.67	18.71	22.93	27.32	31.88	36.64	41.60	46.76	52.14
	6.0%	6.5%	7.0%	7.5%	8.0%	8.5%	9.0%	9.5%	10.0%	10.5%	11.0%
1.0	2.56	2.77	2.99	3.20	3.42	3.64	3.85	4.07	4.29	4.50	4.72
1.5	3.87	4.19	4.52	4.85	5.18	5.51	5.84	6.18	6.51	6.85	7.18
2.0	5.20	5.64	6.08	6.53	6.98	7.43	7.88	8.34	8.79	9.25	9.71
2.5	6.54	7.11	7.67	8.24	8.82	9.39	9.97	10.55	11.13	11.72	12.31
3.0	7.91	8.60	9.29	9.99	10.69	11.39	12.10	12.82	13.54	14.26	14.99
3.5	9.30	10.12	10.94	11.77	12.60	13.44	14.29	15.14	16.00	16.86	17.74
4.0	10.72	11.66	12.62	13.58	14.55	15.53	16.52	17.52	18.53	19.54	20.57
4.5	12.15	13.23	14.32	15.43	16.54	17.67	18.81	19.96	21.12	22.29	23.48
5.0	13.61	14.83	16.06	17.31	18.58	19.85	21.15	22.46	23.78	25.12	26.47
5.5	15.09	16.45	17.83	19.23	20.65	22.09	23.54	25.02	26.51	28.02	29.55
6.0	16.59	18.10	19.64	21.19	22.77	24.37	25.99	27.64	29.31	31.01	32.73
6.5	18.11	19.78	21.47	23.19	24.93	26.71	28.50	30.33	32.19	34.08	35.99
7.0	19.66	21.48	23.34	25.22	27.14	29.09	31.07	33.09	35.14	37.23	39.35
7.5	21.23	23.22	25.24	27.30	29.40	31.53	33.70	35.92	38.17	40.47	42.81
8.0	22.83	24.99	27.18	29.42	31.70	34.03	36.40	38.82	41.29	43.80	46.37
8.5	24.46	26.78	29.15	31.58	34.05	36.58	39.16	41.79	44.48	47.23	50.03
9.0	26.10	28.61	31.16	33.78	36.45	39.19	41.98	44.84	47.76	50.75	53.81
9.5	27.78	30.46	33.21	36.02	38.90	41.85	44.87	47.97	51.13	54.38	57.70
10.0	29.48	32.35	35.30	38.31	41.41	44.58	47.84	51.17	54.59	58.10	61.70
10.5	31.21	34.27	37.42	40.65	43.97	47.37	50.87	54.46	58.15	61.94	65.82
11.0	32.96	36.23	39.59	43.03	46.58	50.23	53.98	57.83	61.80	65.88	70.07
11.5	34.75	38.22	41.79	45.47	49.25	53.15	57.16	61.30	65.55	69.94	74.45
12.0	36.56	40.24	44.04	47.95	51.98	56.14	60.42	64.85	69.41	74.11	78.96
12.5	38.40	42.30	46.32	50.48	54.77	59.20	63.77	68.49	73.37	78.41	83.61
13.0	40.27	44.39	48.66	53.06	57.61	62.32	67.19	72.23	77.44	82.83	88.40
13.5	42.17	46.52	51.03	55.69	60.52	65.52	70.70	76.06	81.62	87.37	93.33
14.0	44.10	48.69	53.45	58.38	63.49	68.80	74.29	80.00	85.92	92.06	98.42
14.5	46.06	50.90	55.92	61.12	66.53	72.15	77.98	84.04	90.34	96.88	103.67
15.0	48.06	53.14	58.43	63.92	69.64	75.58	81.76	88.19	94.88	101.84	109.08
15.5	50.08	55.43	60.99	66.78	72.81	79.09	85.63	92.44	99.55	106.95	114.66
16.0	52.14	57.75	63.60	69.69	76.05	82.68	89.60	96.81	104.35	112.21	120.41
	11.0%	11.5%	12.0%	12.5%	13.0%	13.5%	14.0%	14.5%	15.0%	15.5%	16.0%
1.0	4.72	4.94	5.16	5.37	5.59	5.81	6.03	6.25	6.47	6.69	6.91
1.5	7.18	7.52	7.85	8.19	8.53	8.87	9.21	9.55	9.89	10.24	10.58
2.0	9.71	10.17	10.63	11.10	11.56	12.03	12.50	12.97	13.45	13.92	14.40
2.5	12.31	12.90	13.50	14.10	14.70	15.31	15.91	16.52	17.14	17.76	18.38
3.0	14.99	15.72	16.45	17.20	17.94	18.69	19.45	20.21	20.98	21.75	22.52
3.5	17.74	18.62	19.50	20.39	21.29	22.20	23.11	24.03	24.96	25.90	26.84
4.0	20.57	21.60	22.64	23.70	24.76	25.83	26.91	28.00	29.11	30.22	31.34
4.5	23.48	24.68	25.89	27.11	28.34	29.59	30.85	32.13	33.41	34.72	36.03
5.0	26.47	27.84	29.23	30.63	32.05	33.49	34.94	36.41	37.89	39.40	40.92
5.5	29.55	31.11	32.68	34.27	35.89	37.52	39.18	40.85	42.55	44.28	46.02
6.0	32.73	34.47	36.24	38.03	39.85	41.70	43.57	45.47	47.40	49.36	51.34
6.5	35.99	37.94	39.91	41.92	43.96	46.03	48.14	50.27	52.44	54.65	56.89
7.0	39.35	41.51	43.70	45.94	48.21	50.52	52.87	55.26	57.69	60.17	62.68
7.5	42.81	45.19	47.62	50.09	52.61	55.17	57.78	60.44	63.15	65.91	68.73
8.0	46.37	48.99	51.66	54.38	57.16	59.99	62.88	65.83	68.84	71.91	75.04
8.5	50.03	52.90	55.83	58.82	61.87	64.99	68.18	71.43	74.76	78.16	81.63
9.0	53.81	56.94	60.14	63.41	66.75	70.18	73.68	77.26	80.93	84.68	88.51
9.5	57.70	61.10	64.58	68.15	71.81	75.55	79.39	83.32	87.35	91.48	95.70
10.0	61.70	65.39	69.18	73.06	77.04	81.13	85.33	89.63	94.04	98.57	103.22
10.5	65.82	69.82	73.92	78.14	82.47	86.92	91.49	96.19	101.01	105.97	111.07
11.0	70.07	74.39	78.83	83.40	88.09	92.92	97.90	103.01	108.28	113.70	119.28
11.5	74.45	79.10	83.89	88.83	93.92	99.16	104.56	110.12	115.86	121.77	127.87
12.0	78.96	83.97	89.13	94.46	99.95	105.63	111.48	117.52	123.76	130.20	136.85
12.5	83.61	88.98	94.54	100.28	106.21	112.34	118.68	125.23	132.00	139.00	146.24
13.0	88.40	94.17	100.13	106.31	112.70	119.32	126.17	133.25	140.60	148.20	156.07
13.5	93.33	99.51	105.92	112.55	119.43	126.56	133.95	141.61	149.56	157.81	166.36
14.0	98.42	105.03	111.89	119.02	126.40	134.08	142.05	150.32	158.92	167.85	177.13
14.5	103.67	110.73	118.08	125.71	133.64	141.90	150.48	159.40	168.69	178.36	188.41
15.0	109.08	116.62	124.47	132.64	141.15	150.02	159.25	168.86	178.89	189.34	200.22
15.5	114.66	122.70	131.08	139.83	148.94	158.45	168.38	178.73	189.54	200.82	212.60
16.0	120.41	128.98	137.92	147.27	157.02	167.22	177.88	189.01	200.66	212.83	225.57

TABLE D.III. INTEREST DURING CONSTRUCTION (IDC) IN PERCENTAGE OF TOTAL CAPITAL INVESTMENT COST

CONSTRUCTION PERIOD YEARS	INTEREST RATE										
	1.0%	1.5%	2.0%	2.5%	3.0%	3.5%	4.0%	4.5%	5.0%	5.5%	6.0%
1.0	0.42	0.63	0.84	1.05	1.26	1.47	1.67	1.88	2.08	2.29	2.49
1.5	0.63	0.95	1.26	1.57	1.88	2.19	2.50	2.81	3.11	3.42	3.72
2.0	0.84	1.26	1.68	2.09	2.50	2.91	3.32	3.73	4.13	4.54	4.94
2.5	1.05	1.57	2.09	2.61	3.12	3.63	4.14	4.64	5.15	5.65	6.14
3.0	1.26	1.89	2.51	3.12	3.74	4.35	4.95	5.55	6.15	6.74	7.33
3.5	1.47	2.20	2.92	3.64	4.35	5.05	5.76	6.45	7.14	7.83	8.51
4.0	1.68	2.51	3.33	4.15	4.96	5.76	6.56	7.35	8.13	8.91	9.68
4.5	1.89	2.82	3.74	4.66	5.56	6.46	7.35	8.23	9.11	9.97	10.83
5.0	2.09	3.13	4.15	5.16	6.16	7.16	8.14	9.11	10.08	11.03	11.98
5.5	2.30	3.44	4.56	5.67	6.76	7.85	8.92	9.99	11.04	12.08	13.11
6.0	2.51	3.74	4.96	6.17	7.36	8.54	9.70	10.85	11.99	13.12	14.23
6.5	2.72	4.05	5.37	6.67	7.95	9.22	10,47	11.71	12.94	14.14	15.33
7.0	2.92	4.36	5.77	7.17	8.54	9.90	11.24	12.57	13.87	15.16	16.43
7.5	3.13	4.66	6.17	7.66	9.13	10.58	12.00	13.41	14.80	16.17	17.52
8.0	3.33	4.97	6.57	8.15	9.71	11.25	12.76	14.25	15.72	17.16	18.59
8.5	3.54	5.27	6.97	8.65	10.29	11.92	13.51	15.09	16.63	18.15	19.65
9.0	3.75	5.57	7.37	9.13	10.87	12.58	14.26	15.91	17.54	19.13	20.70
9.5	3.95	5.87	7.76	9.62	11.45	13.24	15.00	16.73	18.43	20.10	21.74
10.0	4.15	6.18	8.16	10.11	12.02	13.90	15.74	17.55	19.32	21.06	22.77
10.5	4.36	6.48	8.55	10.59	12.59	14.55	16.47	18.35	20.20	22.01	23.79
11.0	4.56	6.78	8.94	11.07	13.15	15.20	17.19	19.15	21.07	22.95	24.79
11.5	4.77	7.07	9.33	11.55	13.72	15.84	17.91	19.95	21.94	23.88	25.79
12.0	4.97	7.37	9.72	12.03	14.28	16.48	18.63	20.74	22.79	24.80	26.77
12.5	5.17	7.67	10.11	12.50	14.83	17.11	19.34	21.52	23.64	25.72	27.75
13.0	5.37	7.97	10.50	12.97	15.39	17.75	20.05	22.29	24.48	26.62	28.71
13.5	5.57	8.26	10.88	13.44	15.94	18.37	20.75	23.06	25.32	27.52	29.66
14.0	5.78	8.56	11.27	13.91	16.49	19.00	21.44	23.82	26.15	28.40	30.60
14.5	5.98	8.85	11.65	14.38	17.03	19.62	22.13	24.58	26.96	29.28	31.54
15.0	6.18	9.15	12.03	14.84	17.58	20.23	22.82	25.33	27.78	30.15	32.46
15.5	6.38	9.44	12.41	15.30	18.12	20.85	23.50	26.08	28.58	31.01	33.37
16.0	6.58	9.73	12.79	15.76	18.65	21.46	24.17	26.82	29.38	31.86	34.27
	6.0%	6.5%	7.0%	7.5%	8.0%	8.5%	9.0%	9.5%	10.0%	10.5%	11.0%
1.0	2.49	2.70	2.90	3.10	3.31	3.51	3.71	3.91	4.11	4.31	4.51
1.5	3.72	4.03	4.33	4.63	4.93	5.23	5.52	5.82	6.11	6.41	6.70
2.0	4.94	5.34	5.74	6.13	6.52	6.92	7.31	7.70	8.08	8.47	8.85
2.5	6.14	6.64	7.13	7.62	8.10	8.58	9.07	9.54	10.02	10.49	10.96
3.0	7.33	7.92	8.50	9.08	9.66	10.23	10.80	11.36	11.92	12.48	13.03
3.5	8.51	9.19	9.86	10.53	11.19	11.85	12.50	13.15	13.79	14.43	15.06
4.0	9.68	10.44	11.20	11.96	12.70	13.44	14.18	14.91	15.63	16.35	17.06
4.5	10.83	11.69	12.53	13.37	14.19	15.02	15.83	16.64	17.44	18.23	19.01
5.0	11.98	12.91	13.84	14.76	15.67	16.57	17.46	18.34	19.21	20.08	20.93
5.5	13.11	14.13	15.13	16.13	17.12	18.09	19.06	20.01	20.96	21.89	22.81
6.0	14.23	15.33	16.41	17.49	18.55	19.60	20.63	21.66	22.67	23.67	24.66
6.5	15.33	16.51	17.68	18.82	19.96	21.08	22.18	23.27	24.35	25.42	26.47
7.0	16.43	17.69	18.92	20.14	21.35	22.54	23.71	24.86	26.00	27.13	28.24
7.5	17.52	18.84	20.15	21.45	22.72	23.97	25.21	26.43	27.63	28.81	29.98
8.0	18.59	19.99	21.37	22.73	24.07	25.39	26.69	27.96	29.22	30.46	31.68
8.5	19.65	21.12	22.57	24.00	25.40	26.78	28.14	29.47	30.79	32.08	33.35
9.0	20.70	22.24	23.76	25.25	26.71	28.15	29.57	30.96	32.32	33.67	34.98
9.5	21,74	23.35	24.93	26.48	28.01	29.51	30.97	32.42	33.83	35.22	36.59
10.0	22.77	24.44	26.09	27.70	29.28	30.84	32.36	33.85	35.31	36.75	38.16
10.5	23.79	25.53	27.23	28.90	30.54	32.15	33.72	35.26	36.77	38.25	39.70
11.0	24.79	26.59	28.36	30.09	31.78	33.44	35.06	36.64	38.20	39.72	41.20
11.5	25.79	27.65	29.47	31.26	33.00	34.70	36.37	38.00	39.60	41.15	42.68
12.0	26.77	28.69	30.57	32.41	34.20	35.95	37.67	39.34	40.97	42.57	44.12
12.5	27.75	29.73	31.66	33.54	35.39	37.18	38.94	40.65	42.32	43.95	45.54
13.0	28.71	30.74	32.73	34.67	36.55	38.39	40.19	41.94	43.64	45.30	46.92
13.5	29.66	31.75	33.79	35.77	37.70	39.59	41.42	43.20	44.94	46.63	48.28
14.0	30.60	32.75	34.83	36.86	38.84	40.76	42.63	44.44	46.21	47.93	49.60
14.5	31.54	33.73	35.86	37.94	39.95	41.91	43.81	45.66	47.46	49.21	50.90
15.0	32.46	34.70	36.88	39.00	41.05	43.05	44.98	46.86	48.69	50.46	52.17
15.5	33.37	35.66	37.88	40.04	42.13	44.16	46.13	48.04	49.89	51.68	53.41
16.0	34.27	36.61	38.88	41.07	43.20	45.26	47.26	49.19	51.06	52.88	54.63
	11.0%	11.5%	12.0%	12.5%	13.0%	13.5%	14.0%	14.5%	15.0%	15.5%	16.0%
1.0	4.51	4.71	4.90	5.10	5.30	5.49	5.69	5.88	6.08	6.27	6.46
1.5	6.70	6.99	7.28	7.57	7.86	8.15	8.43	8.72	9.00	9.28	9.57
2.0	8.85	9.23	9.61	9.99	10.37	10.74	11.11	11.48	11.85	12.22	12.59
2.5	10.96	11.43	11.89	12.36	12.82	13.27	13.73	14.18	14.63	15.08	15.52
3.0	13.03	13.58	14.13	14.67	15.21	15.75	16.28	16.81	17.34	17.86	18.38
3.5	15.06	15.69	16.32	16.94	17.56	18.17	18.77	19.38	19.98	20.57	21.16
4.0	17.06	17.76	18.46	19.16	19.85	20.53	21.21	21.88	22.54	23.21	23.86
4.5	19.01	19.79	20.56	21.33	22.08	22.83	23.58	24.32	25.05	25.77	26.49
5.0	20.93	21.78	22.62	23.45	24.27	25.09	25.89	26.69	27.48	28.26	29.04
5.5	22.81	23.73	24.63	25.53	26.41	27.28	28.15	29.00	29.85	30.69	31.52
6.0	24.66	25.63	26.60	27.55	28.50	29.43	30.35	31.26	32.16	33.05	33.92
6.5	26.47	27.50	28.53	29.54	30.54	31.52	32.49	33.45	34.40	35.34	36.26
7.0	28.24	29.33	30.41	31.48	32.53	33.56	34.58	35.59	36.58	37.56	38.53
7.5	29.98	31.13	32.26	33.37	34.47	35.55	36.62	37.67	38.71	39.73	40.73
8.0	31.68	32.88	34.06	35.23	36.37	37.50	38.61	39.70	40.77	41.83	42.87
8.5	33.35	34.60	35.83	37.04	38.22	39.39	40.54	41.67	42.78	43.87	44.94
9.0	34.98	36.28	37.55	38.80	40.03	41.24	42.42	43.59	44.73	45.85	46.95
9.5	36.59	37.93	39.24	40.53	41.80	43.04	44.26	45.45	46.62	47.77	48.90
10.0	38.16	39.54	40.89	42.22	43.52	44.79	46.04	47.26	48.46	49.64	50.79
10.5	39.70	41.11	42.50	43.86	45.20	46.50	47.78	49.03	50.25	51.45	52.62
11.0	41.20	42.66	44.08	45.47	46.83	48.17	49.47	50.74	51.99	53.21	54.40
11.5	42.68	44.17	45.62	47.04	48.43	49.79	51.11	52.41	53.67	54.91	56.12
12.0	44.12	45.64	47.13	48.58	49.99	51.37	52.71	54.03	55.31	56.56	57.78
12.5	45.54	47.09	48.60	50.07	51.51	52.91	54.27	55.60	56.90	58.16	59.39
13.0	46.92	48.50	50.03	51.53	52.99	54.40	55.78	57.13	58.44	59.71	60.95
13.5	48.28	49.88	51.44	52.95	54.43	55.86	57.26	58.61	59.93	61.21	62.46
14.0	49.60	51.23	52.81	54.34	55.83	57.28	58.69	60.05	61.38	62.67	63.92
14.5	50.90	52.55	54.14	55.70	57.20	58.66	60.08	61.45	62.78	64.07	65.33
15.0	52.17	53.84	55.45	57.02	58.53	60.00	61.43	62.81	64.14	65.44	66.69
15.5	53.41	55.10	56.73	58.30	59.83	61.31	62.74	64.12	65.46	66.76	68.01
16.0	54.63	56.33	57.97	59.56	61.09	62.58	64.01	65.40	66.74	68.03	69.28

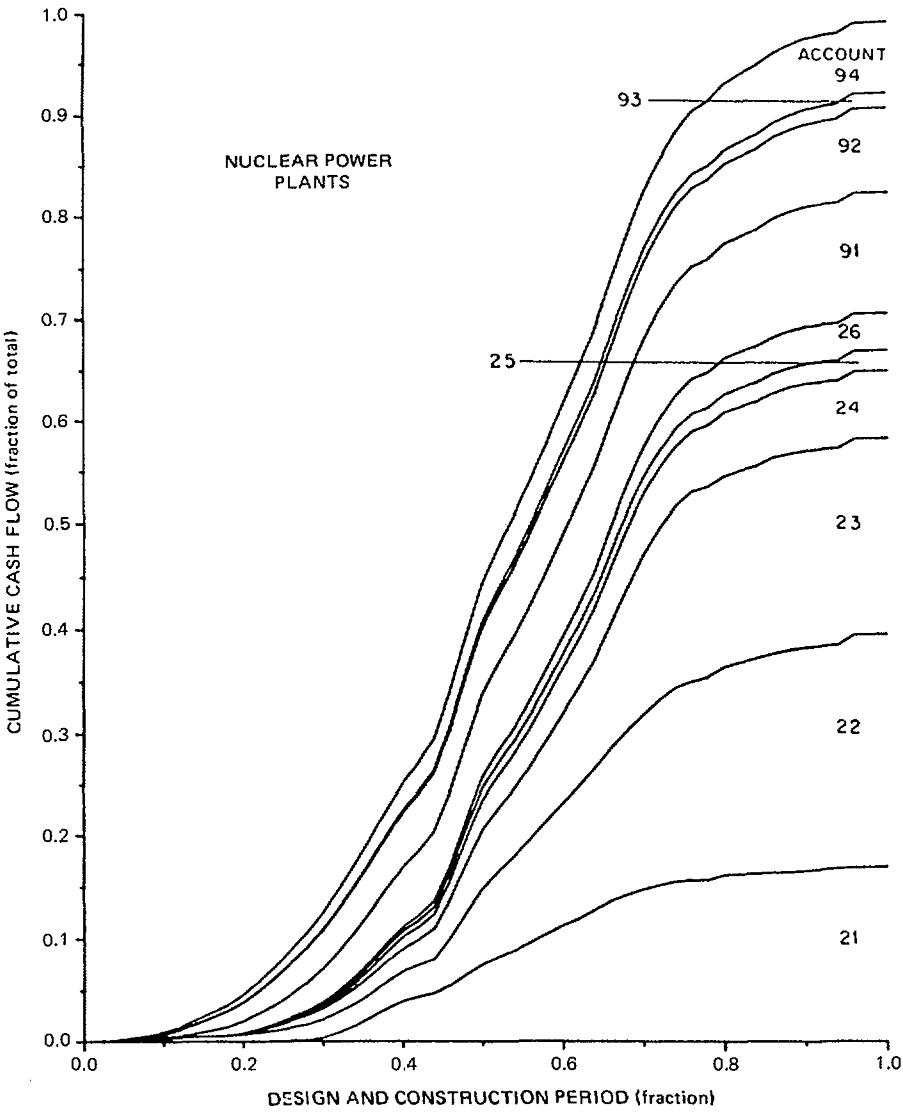


FIG.D.3. Typical cumulative cash flow curves for major direct cost accounts: nuclear power plants (from [2]).

ahead of the optimization run of the planning study to analyse the cash flow of any assumed system expansion plan, thus permitting the establishment of certain ground rules for the acceptable values of the variables to be optimized (i.e. types and number of the units required for addition). The program can also be used for a more detailed analysis of the best expansion policy found by WASP. At this stage, other considerations not previously allowed for in the optimization process may be taken into account.

The method used on CONCOS for the determination of cash flows is as follows.

CONCOS provides the user with detailed and summary reports of the different cost types depending on the options activated by means of control cards. First, the set of alternative plants which are considered by the expansion plan must be given as input information. The construction costs read in represent construction costs plus IDC and have to be reduced to the fore cost (e.g. pure construction costs). From this and other data read in, a basic calculation per alternative plant is performed concerning the distribution of costs over the given time of construction.

The calculation of IDC and construction cost + IDC is optional and controlled by input data. The distribution of fuel investment cost is assumed to cover a period of 18 months.

The distribution function of cost versus a given period of time for construction of a plant follows an S-type curve taken from ORCOST. The curve (Fig.D.2) is a polynomial of 7th order but given as

$T = f(C)$ (where T is time and C is cost)

while

$C = g(T)$ is required.

C is evaluated in the program out of a given T by means of an iterative technique with an accepted tolerance of ±0.01%.

After this basic calculation, a number of cards are read, each representing one or more units or projects of a thermal or hydroelectric plant and pumped storage plant, respectively, to be built in the same year. According to the type of plant and the given year of operation, the distribution of cost is assigned to the proper years and added to the totals per year.

Depending on the output option, the detailed reports are printed, followed by a summary list.

The main input data required for the execution of the program are:

- General information for the run: name of country; options controlling output tables desired; first year of study and total number of years; number of alternative plants; annual interest rate.
- Per alternative plant: capital and fuel investment cost distributed into local and foreign components; fraction of IDC included in the capital cost; construction time; plant capacity; name of the plant.
- Per unit addition: type of alternative plant; year of addition; number of units or projects added in this year.

The main restrictions of the program can be summarized as follows:

- 30 years maximum length of the study period,
- 9 years maximum construction time of any alternative plant,
- 50 plants for the maximum number of alternatives to be considered.

D.2. FUEL REQUIREMENTS

D.2.1. Nuclear fuel cycle cost treatment (FUELCASH)

Estimates of the levelized nuclear fuel cost over the operating life of the power plant can be made by the use of computer programs such as FUELCASH. This code, described in Appendix C of Ref. [6], was developed for use in connection with the WASP methodology for conducting nuclear power planning studies for IAEA Member States. FUELCASH permits assessment of the generating costs of the net fuel cycle for the lifetime of the reactor. Based on a 626 MW(e) PWR, the program calculates the cost for each fuel batch during the economic life of the reactor, and the present worth value of each cost item is determined in order to find the levelized cost of generation. In these calculations, due consideration is given to the sign of those payments which represent an actual credit. An energy generation schedule is also prepared with allowance for planned refuelling and maintenance periods. Appropriate allowances are made for the type of nuclear fuel cycle, e.g. with or without reprocessing. The results of the calculations can be used to provide estimates for other reactor sizes using approximate cost-scaling laws.

The program can be used to analyse several cases for the same reactor conditions, and a large amount of information is needed in each case. This starts with general input for the run, given by cards as follows:

(1) A title card identifiying the problem,
(2) A card with primary data on the case being studied,
(3) A card for controlling input and options,
(4) The groups of basic cards specified on the card for controlling input and options.

If there is a sequence of cases, the first in the sequence must contain enough information to define a problem completely. Provided that the reactor in question is the same one, FUELCASH-II enables subsequent cases to be run by making changes only in the basic data that one wishes to modify and without having to prepare the entire run.

The group of basic cards can contain some or all of the following:

(1) Information on changes in the internal library of the code (optional) and net station unit heat rates at 100%, 75% and 50% of net station output;
(2) Information on the reactor operating regime (optional) – percentage of operating time at a given power level, plant availability factors;

(3) Information on the needs of the system – net station unit heat rates or net station outputs and capacity factors as a function of time;
(4) Cost information – costs of materials and processes as a function of time for each type of fuel assembly (if there is only one type, this information applies to all the assemblies);
(5) Information on post-irradiation periods – defining the times when fuel transport and reprocessing are paid for and the times when the credits are received for final uranium and plutonium;
(6) Information on pre-irradiation periods for fuel fabrication – defining the times for the series of payments and final payment (if there is one) to cover the cost of the fuel fabrication component;
(7) Information on pre-irradiation periods for natural uranium – defining the times for the flow of payments and the final payment (if there is one) to cover the cost of the component corresponding to the purchase of natural uranium concentrates;
(8) Information on pre-irradiation periods for enrichment – defining the times for the flow of payments and the final payment (if there is one) to cover the cost of the enrichment component;
(9) Information on pre-irradiation periods for the initial plutonium – defining the times for the series of payments and the final payment (if there is one) to cover the cost of the initial plutonium;
(10) Information on fuel batch physics for all the assemblies – defining initial and final masses of uranium and plutonium, total and per-cycle burnups, initial and final enrichments (information on fuel loading and unloading is also included);
(11) Information on the cost per batch for all the assemblies – defining the costs per batch of the initial and final uranium, the initial and final plutonium, fabrication, transport, reprocessing, and the initial and final fuel (information which may be received in specific offers).

The standard printed output produced by execution of FUELCASH contains a detailed ordered summary of the input data in order to permit verification of these data, as well as:

(1) A schedule of loading and unloading dates for each batch;
(2) A table of per-batch payments for each cycle component, including the equivalent decimal data of the payment, the total payment made and the present worth accumulated per component;
(3) The continuous or accumulated present worth of all payments and the total of payments actually made and credits received;
(4) A table of power generation per cycle, including the initial and final dates of each cycle, the cycle duration, the days of operation and the energy produced (in kW·h and Btu) (the accumulated present worth of these quantities is also included);

(5) The total energy produced and the present worth discounted fuel cycle cost (in mills/kW·h).

A sample problem has been developed to illustrate the printed output of the program (see Appendix F).

D.2.2. Nuclear fuel cycle requirements (SCENARIOS)

The SCENARIOS package system permits evaluation of the requirements for nuclear fuel cycle materials and services arising from a determined deployment programme for reactor utilization, over a given period of time. The code was developed to meet the needs of the INFCE study carried out in 1978–1980 [7]. A detailed description of the code appears in Ref. [8].

SCENARIOS is a straightforward simulation model of the materials flow through the various process steps in the nuclear fuel cycle. The model was designed to accept as input the deployment programmes for the various reactor types under consideration and the operational characteristics for each reactor type. Additional input information consists of the strategies and characteristics of the fuel cycle covering spent fuel reprocessing and storage facilities and the lead time, delay times and efficiencies for each fuel cycle operation.

The simulation of the reactor programme and fuel cycle strategy produces calculated results on nuclear fuel and heavy water requirements, enrichment needs and demands for other fuel cycle services.

The program is organized in several modules to allow for greater flexibility in the use of the system and its application to the INFCE study. Figure D.4 is a schematic representation of the calculation flow through the SCENARIOS system. It can be seen from this figure that the SCENARIOS package consists of a set of computer programs and associated input and output files. Input data files can take the form of a card file or a Librarian file (LIBRARIAN is a commercially available generalized data storage and retrieval system). Each computer program is executed independently and generates either output reports, disk files for use by another program, or both.

The MBAL computer program simply transfers the information given as input data to a disk file containing reactor characteristics by reactor type. No calculations are made by this program and the only report written is a listing of the reactor model data.

The MASFLO program uses a reactor deployment schedule given as input data and the appropriate reactor models from the file created by MBAL in order to calculate all annual charges and discharges from each plant over the planning period. The results are listed in output reports and written on a disk file for later use by the SYMM program. MASFLO also calculates forward commitments of uranium and separative work and estimates of the plutonium inventory in reactors.

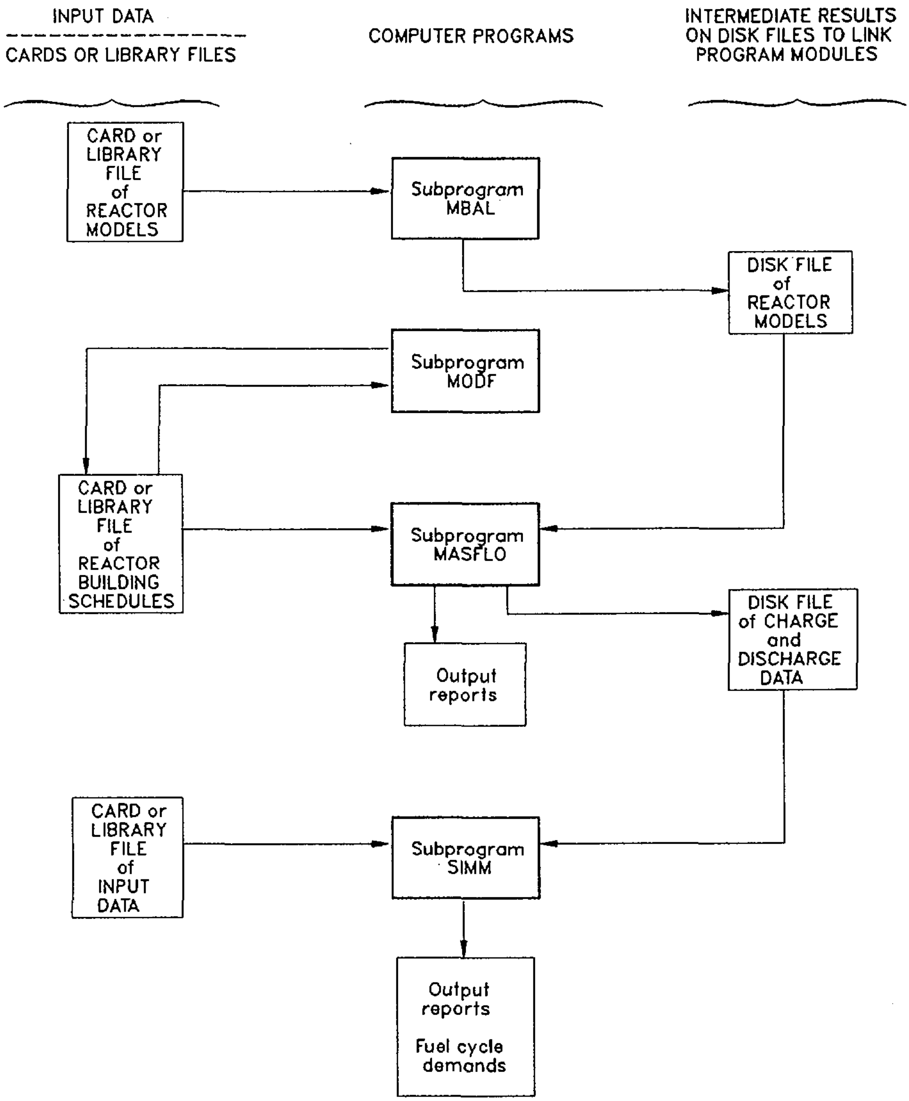


FIG.D.4. Scheme of calculational flow through the SCENARIOS system.

Finally, the SYMM program uses the MASFLO-created disk file, together with additional input data to calculate front and back end of fuel cycle requirements. The input data corresponds to fuel cycle information such as lead and lag times, process efficiencies, capacities and deployment schedules for reprocessing plants and characteristics of away-from-reactor spent fuel storage plants. For a single charge and discharge file that has been calculated for a particular reactor development schedule, several executions of the SYMM program may be desired in order to evaluate the effects of changes in the fuel cycle data.

The MODF program is used to automate the changing of reactor types in an existing file containing a reactor deployment schedule. One file can be read, a series of changes made, and a new file generated. Some percentage of one reactor type may be changed to another, or specified amounts of a reactor type may be changed. Eventually, a series of these changes may be made to a single file. The program is used to make changes in large files more easily and faster and to help prevent errors.

There are certain limitations to the application of the program for a case study and the calculations performed. These limitations are examined below, together with some special features of the code.

First, SCENARIOS does not execute any optimizations; nor does it attempt to balance supply and demand of resources such as plutonium. All calculations are made in considerable detail but are simple. These features, combined with the considerable amount of input, were chosen to allow greater flexibility in the use of the system.

The maximum number of reactor types that can be considered by a deployment programme is 25. Up to 15 different fuel types can be considered, but the maximum number of possible fuel types that can be utilized for a single reactor type is limited to 3. Moreover, the load factor curves used in the program are dimensioned for a maximum plant operating life of 40 years. The maximum planning period length is 50 years.

Calculations for each year take into consideration all fuel charges and discharges of each reactor occurring during these years. To calculate forward commitments, the annual calculations are made for each reactor to the end of its life. Thus a maximum of 85 years can be defined for the length of the planning period plus the life of the reactors.

Several countries (up to five) may be considered in a single execution of the simulation process. This facilitates the application of the program for regional cases not only in terms of data preparation but also in regard to the provision of combined results for the region (as needed in the INFCE study).

Finally, up to ten types of fuel reprocessing plants and ten types of away-from-reactor fuel storage plants may be considered.

D.3. POWER SYSTEM ANALYSIS

Power system analysis involves the application of several interrelated studies, each one requiring the use of specialized techniques and, in most cases, the use of computers (see Chapter 9). A large variety of computer models are available for these purposes and these are referred to in Chapter 3. The following models can be used for approximate calculations such as are usually performed for long-term expansion planning studies.

D.3.1. Maintenance schedules for power generating systems (MASCO)

MASCO was written to be used in conjunction with the WASP program. The present version of this code written in FORTRAN [9] is intended for use in connection with the WASP methodology. MASCO prepares a power system maintenance schedule for up to 12 maintenance periods, assuming that each generating unit requires one full period for maintenance, although larger or shorter periods of maintenance for a group of units can be simulated by increasing or decreasing the number of units in the input data, so that the product of the number of units and maintenance time per unit are approximately correct.

The algorithm used by MASCO allocates the maintenance of a given unit in the period where the 'maintenance space' is maximum (absolute or relative to the peak load, or both, according to the input option used) taking into account any previous scheduling of maintenance of other units.

The 'maintenance space', or reserve available in each maintenance period, is calculated by taking the total system thermal capacity (assumed to be constant over the total scheduling period), adding the predicted hydroelectric capacity and subtracting the predicted peak load demand. As a unit is scheduled in a maintenance period, the available reserve in that period is reduced by the capacity of the unit being removed from the system for maintenance.

The program permits forcing the maintenance of a given unit in a desired period. If this option is chosen for some units, they will be scheduled for maintenance in the desired periods. Scheduling of the remaining units will be performed in a decreasing way starting by the largest unit still unscheduled, according to the option chosen (largest absolute or relative maintenance space). This will result in a more or less uniform net (or fractional) reserve capacity in all periods. The procedure is described in Fig.D.5.

The input data are the number of maintenance periods, the total system thermal capacity, the scheduling options required (e.g. maximum absolute reserve per period, maximum relative reserve, or both), the hydroelectric capacity for each period, the peak load demand for each period, and the power plant specifications.

The printout of the program gives, for each case considered in the same run, a summary of available thermal and hydroelectric capacities, with maximum load and maintenance space for each period described. This is followed by the maintenance schedule for the units and the resulting reserve margins, according to the selected options.

D.3.2. Frequency decay after sudden loss of generation (FRESCO)

The dynamic response of a power system to a sudden loss of generation is generally characterized by two distinct components of power variation in the

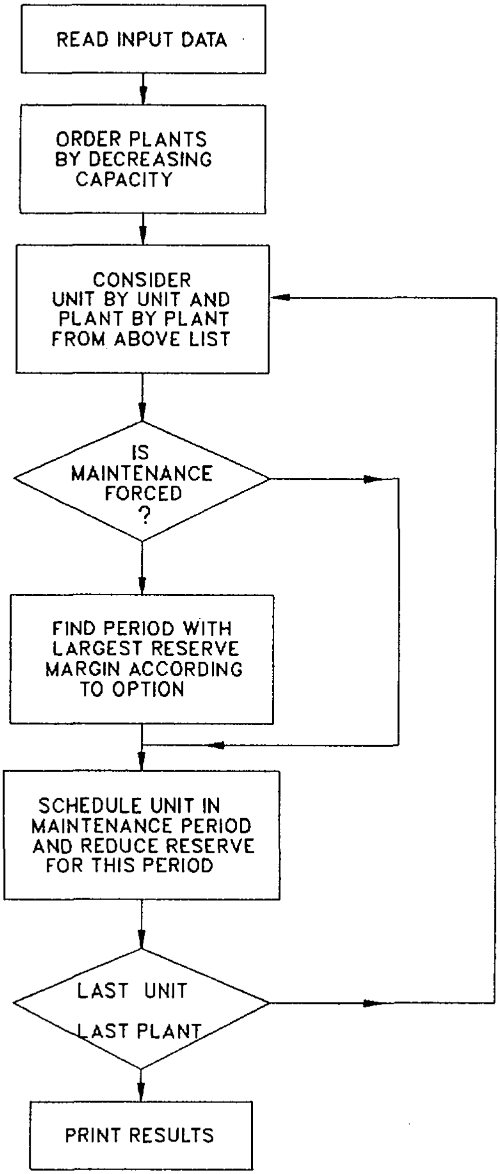


FIG.D.5. Flow chart of the MASCO computer program.

period 10–20 s immediately following the disturbance. These are the faster transient oscillations in synchronizing power (period typically 1–2 s) which arise owing to angular disturbances from the steady state and the slower variation in prime mover power (period typically 10–20 s) owing to the primary regulation effects of the governor/turbine response to frequency change.

The ability of a system to remain in synchronism following a given angular disturbance is mainly dependent on the transfer impedances between sources, i.e. on the transmission network. System faults will usually give rise to much larger angular deviations than loss of generation and will thus dictate the requirements of the transmission network for retention of transient stability. Thus, provided the transmission network has been designed with due regard to transient fault studies and the emergency redistribution of power flow resulting from plant outages, it is reasonable to assume that synchronous stability will be retained following a sudden loss of generation. (A possible exception to this premise is the case of a sudden loss of generation immediately following a severe system fault, but such second contingency events are not considered here.)

Assuming that the system remains in synchronism, then, neglecting losses (which may be assumed constant throughout the disturbance), the rate of change of stored kinetic energy (i.e. frequency) at any instant is equal to the difference between power input to the system (i.e. prime mover power) and power output (i.e. load):

$$(2 \times H_T) \times (f_a) \times (df_a/dt) = P_{mk} - P_L \tag{D.1}$$

where H_T is the total inertia constant of connected machines including rotating loads (typically 3.0 to 5.0), P_{mk} is the sum of prime mover input power of connected generators, P_L is the total connected load, and f_a is the average system frequency.

Since the power system is assumed to remain in synchronism, the transmission network may be neglected and Eq. (D.1) may be modelled by a number of prime movers and their generating units feeding a single block load as described below. The effect of any load-shedding scheme on the frequency response can also be examined to determine the permissible amount of load to be shed in order to prevent excessive frequency drops and possible system collapse.

The program FRESCO permits study of the frequency response of power systems to sudden loss of large generating units. In its present version, it is intended for use in connection with the WASP methodology.

FRESCO is based on the Average System Frequency Model developed by ANS, UK, for the needs of a study carried out by the IAEA in 1972/1973 (see Appendix H of Ref. [10]. The main assumptions of the model, and hence of FRESCO, are:

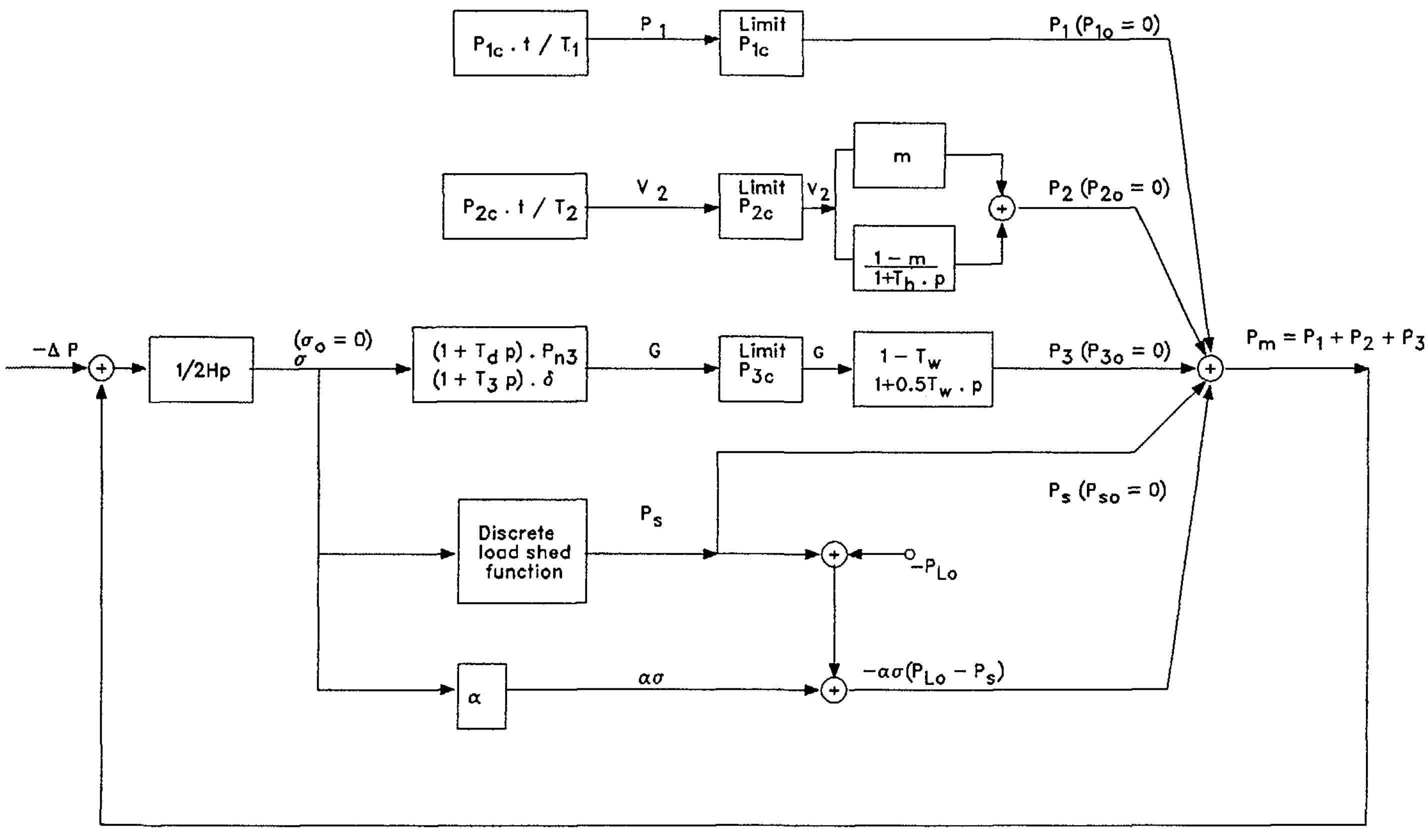


FIG.D.6. Block transfer diagram of the FRESCO program.

- The transmission system is neglected, assuming that transient fault studies and the emergency distribution of power flow resulting from plant outages are taken into consideration in detailed transmission system design.
- An energy approach is used such that the rate of change of stored kinetic energy (i.e. frequency) at any instant is equal to the difference between power input to the system (i.e. prime mover power) and power output (i.e. load).
- Secondary frequency regulation is neglected. The effect of this type of regulation (control dispatchers) is noticed in the longer-term frequency variation (time-scale of minutes).
- The total load is assumed to depend only on average system frequency. Variations due to oscillating components arising from synchronizing swings are neglected. Load varying with voltage can, if desired, be sufficiently represented by conversion to an equivalent load varying with frequency.
- Boiler response is neglected in thermal plants; non-regulating base load units are assumed to have constant power output and only the governor/turbine response of regulating units is considered.
- Governor response is based on average system frequency (the oscillating component due to synchronizing swings is generally at a much shorter time period than the governor/turbine response time and does not appreciably affect the prime mover output).
- Regulating units are lumped together in three categories of plant:
  - Thermal non-reheat
  - Thermal reheat
  - Hydroelectric, including pumped storage (working in the generating mode).

On the basis of these assumptions, the components of the power system are represented by a set of coupled differential equations as shown schematically in Fig.D.6. These equations are solved in a stepwise manner assuming that their coefficients are constant within the time step used. In spite of this simplification, accuracy is sufficient provided that a small enough time step is used.

The input data required by FRESCO include:

- Settings for load shedding schemes (if any),
- Integration time step for calculations,
- Maximum time for which frequency response is to be investigated,
- Parameters concerning each of the plants available in the system,
- Power system characteristics,
- Load being served,
- Amount of power loss.

TABLE D.IV. PARAMETERS OF THE FRESCO PROGRAM

Symbol	Range	Typical value	Description
2H	4 – 12	–	Total inertia constant of the system after loss of generation
α	1.5 – 2.0	2.0	Load regulation coefficient of the system
T_1	0.5 – 1.5	1.0	Valve time of non-reheat thermal plant
T_2	0.5 – 1.5	1.0	Valve time of steam valve of reheat thermal plant
T_h	6 – 10	8.0	Time constant of reheat thermal plant
m	0.2 – 0.5	0.3	Fraction of power in high pressure section of turbine
δ	0.02 – 0.06	0.03	Permanent droop of the hydroelectric plant speed governor
δ_t	0.2 – 1.0	0.3	Temporary droop of the hydroelectric plant speed governor
T_d	2.5 – 25	5.0	Dashpot time constant of the hydroelectric plant speed governor
T_g	0.2 – 0.4	0.2	Response time of the hydroelectric plant speed governor
T_w	0.5 – 5.0	1.0	Water starting time in the hydro-electric plant intake
$\delta \cdot T_3$	0.75 – 5.0	1.8	$T_g + T_d(\delta + \delta_t)$
P_{Lo}	0.4 – 1.0	1.0	Load being served before loss of generation
ΔP	0 – 0.25	–	Loss of generation at time t = 0, normally the largest unit of the system
P_{1c}	0.1 – 0.2 of nominal non-reheat thermal capacity	0.1	Maximum fast spinning reserve available from the non-reheat thermal plant
P_{2c}	0.1 – 0.2 of nominal reheat thermal capacity	0.1	Maximum fast spinning reserve available from the reheat thermal plant

TABLE D.IV. (cont.)

Symbol	Range	Typical value	Description
P_{n3}	$0 - 1.0$	–	Nominal capacity of hydroelectric plant used for regulating purposes (includes emergency hydroelectric and possibly some pumped storage working in the generating mode)
P_{3c}	$0 - \frac{2}{3}P_{n3}$	$0.25\ P_{n3}$	Maximum fast spinning reserve available from hydroelectric plant
σ_1	–	-0.01	Frequency deviation at which first stage of load shedding is applied
σ_2	–	-0.02	Frequency deviation at which second stage of load shedding is applied
σ_3	–	-0.03	Frequency deviation at which third stage of load shedding is applied
P_{s1}	$0 - 0.05$	0.04	Amount of load shed at frequency deviation σ_1
P_{s2}	$0 - 0.10$	0.08	Amount of load shed at frequency deviation σ_2
P_{s3}	$0 - 0.15$	0.12	Amount of load shed at frequency deviation σ_3

Notes:

P_L, ΔP, P_{1c}, P_{2c}, P_{3c}, P_{n3}, P_{s1}, P_{s2}, and P_{s3} are expressed in *per unit* of an arbitrary base power, normally the peak load P_{Lo}.

H is measured in MJ, and is expressed in seconds when referred to the base power chosen.

T_1, T_2, T_h, T_d, T_g and T_w are expressed in seconds.

α, m, δ and δ_t are dimensionless magnitudes.

σ_1, σ_2 and σ_3 are expressed in *per unit* of normal frequency (50 Hz or 60 Hz) and therefore appear as dimensionless magnitudes.

TABLE D.V. TYPICAL VALUES OF INERTIA CONSTANTS AS A FUNCTION OF GENERATING SET SIZE

Set size (MW)	H (MJ)
Thermal units[a]:	
1500	4100
1200	3500
1000	3000
800	2500
600	2000
400	1500
200	850
100	500
50	300
Hydroelectric units[a]:	
Range: 2 – 3 MJ/MW	
Use: 2.5 MJ/MW as a typical value	

[a] H, expressed in MJ/MW, decreases as the thermal unit size increases; for hydroelectric units, the reverse is true.

Note: The total inertia of the power system is the inertia of the generating system plus the inertia of the rotating loads. Unless better data are available, the total inertia of the rotating loads can be assumed equal to the total inertia of the generating plants.

The output of the FRESCO program consists of a summary of the input data used, followed by the results of the analysis. The latter include for each time step chosen for printing:

- System frequency deviations,
- Amount of power shed,
- Fast spinning reserve used at this time step from the various plant types,
- Incremental opening of the steam valve of the reheat thermal plant,
- Change in the opening of the hydroelectric plant inlet vane.

Tables D.IV and D.V show some of the input parameters required by the FRESCO model together with the normal range of values for each variable.

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Appendix E

DEFINITIONS AND ENERGY PRODUCT DATA

One of the complicating factors in energy planning is the lack of a consistent set of definitions of energy products and their characteristics. The planner must deal with inconsistencies among countries, among international organizations, and even within a single country. The information given in this appendix is designed to provide a convenient reference for a given energy planning effort. It should be noted that there is no universal agreement on all of this information.

E.1. BASIC ENERGY UNITS

The unit most widely recognized as the standard for energy units is the joule:

$$1 \text{ joule (J)} = 1 \text{ newton-metre} = 1 \frac{\text{kg}\cdot\text{m}^2}{\text{s}^2}$$

The more commonly used energy units can be expressed in joules:

1 British thermal unit (Btu)	= 1055 J
1 kilocalorie (kcal) = 10^3 calories (cal)	= 4187 J
1 kilowatt-hour (kW·h)	= 3.6×10^6 J

In many places, energy is expressed in terms of fuel equivalents. There is no universal definition of these fuel equivalents expressed in terms of joules. Some of the more common uses are as follows:

1 TCE (tonne (t) of coal equivalent) = 7.0×10^6 kcal = 29.3×10^9 J
1 TOE (t of oil equivalent) = 10.0×10^6 kcal = 41.9×10^9 J
1 BOE (barrel of oil equivalent, based on 7.5 barrels/t)
= 1.33×10^6 kcal = 5.58×10^9 J

E.2. ENERGY PRODUCT UNITS

The measurement of energy product characteristics varies even more widely than the basic energy units. There are wide variations in product density, heat content and other factors even for the same product (e.g. coal). The energy planner is well advised to obtain specific information appropriate to the situation. The information presented on Table E.I illustrates *average* values only; it should be used only when no other information is available.

E.3. ENERGY PRICES

The price of energy products on the international market is a key element in an energy planning analysis. The energy planner is advised to use locally available information wherever possible to reflect the situation under study. The data presented here are illustrative only.

E.3.1. Crude oil

Table E.II gives the official price of crude oil from a variety of sources. It should be noted that transactions on the 'spot market' and special-arrangement long-term contracts may differ considerably from these data.

E.3.2. Coal

Coal prices on the international market are subject to wide fluctuations. The viability of coal as an internationally traded energy commodity depends heavily on the oil price. Table E.III gives a typical breakdown of coal costs.

E.3.3. Natural gas

Because gas is not an easily transportable energy source, its use is more restricted than oil or coal. Table E.IV shows the additional costs incurred for transport of gas. Note that these costs must be *added* to well-head gas prices.

E.3.4. Uranium

Uranium is traded internationally in a variety of forms including U_3O_8 yellowcake, UO_2 enriched uranium, and fabricated fuel rods. Table E.V gives typical cost estimates for nuclear fuel.

TABLE E.I. AVERAGE VALUES FOR ENERGY PRODUCTS

Product	Density[a]		Fuel equivalents			Heat content
	Specific gravity	(barrels/t)	TCE/t[a]	TOE/t[b]	BOE/t[b]	10^6 J/kg[b]
Petroleum:						
Crude oil	0.84	7.5	1.454	1.017	7.635	42.60[c]
Liquefied petroleum gas	0.54	11.65	1.554	1.087	8.160	45.53
Gasoline	0.74	8.50	1.500	1.049	7.876	43.95
Kerosene/jet fuel	0.81	7.77	1.474	1.031	7.740	43.19
Gas-diesel oil	0.87	7.23	1.450	1.014	7.614	42.49
Residual fuel oil	0.95	6.62	1.416	0.990	7.435	41.49
Natural gas	(d)	(d)	–	–	–	0.143[e]
Coal:						
Hard coal	(d)	(d)	1.00	0.699	5.251	29.30
Lignite/brown coal	(d)	(d)	0.385	0.269	2.022	11.28

[a] Source: 1979 Yearbook of World Energy Statistics, United Nations, New York (1981).
[b] Computed using conversion factors given previously.
[c] Note that this does not exactly equal the value of 41.9×10^9 J/t given in Section E.1. This is because the unit 'Tonne of Oil Equivalent' is defined somewhat arbitrarily as 10.0×10^6 kcal. Thus, the world average crude oil has a heat content slightly higher (42.60×10^6 J/kg) than this arbitrarily defined unit. This illustrates the difficulties frequently encountered in unit definition.
[d] Not applicable.
[e] J/m^3 of gas at 15°C and 1015 mbar, dry.

TABLE E.II. CRUDE OIL SELLING PRICES

Area Country: Crude type (API gravity)	Prices, current US $ per barrel as of 1 Jan.									
	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
NORTH AMERICA										
Mexico: Isthmus (34)	(a)	(a)	(a)	12.10	13.35	13.40	14.10	32.00	38.50	35.00
Canada: Canadian Heavy (22)[b]	(a)	(a)	(a)	(a)	(a)	(a)	14.25	26.60	34.09	28.74
CENTRAL AND SOUTH AMERICA										
Venezuela: Tia Juana (26)	E2.63	E10.13	E10.59	11.12	12.72	12.82	13.36	25.20	32.88	32.88
Ecuador: Oriente (30)	E2.14	E11.29	11.45	11.45	13.00	12.65	13.03	E33.50	40.06	34.25
WESTERN EUROPE										
UK: Forties (37)	(a)	(a)	(a)	(a)	14.10	13.65	15.50	29.75	39.25	36.50
Norway: Ekofisk (40)	(a)	(a)	(a)	(a)	14.33	14.20	15.10	32.50	40.00	37.25
MIDDLE EAST										
Saudi Arabia: Arabian Light (34)	E2.41	E10.84	10.46	11.51	12.09	12.70	13.34	26.00	32.00	34.00
Iran: Iranian Light (34)	E2.40	E11.04	10.67	11.62	12.81	12.81	13.45	30.37	37.00	34.20
Kuwait: Kuwait Blend (31)	E2.31	E10.74	10.37	11.30	12.37	12.27	12.83	27.50	35.50	32.30
Abu Dhabi: Murban (39)	E2.47	E11.75	10.87	11.92	12.50	13.26	14.10	29.56	36.56	35.50
Iraq: Basrah Light (35)	E2.38	E10.85	10.48	11.53	12.58	12.58	13.21	27.96	35.96	34.93
AFRICA										
Algeria: Saharan (44)	E3.30	14.00	12.00	12.85	14.30	14.25	14.81	30.00	40.00	37.00
Libya: Es Sider (37)	E2.87	E11.98	E11.10	12.21	13.74	13.80	14.52	34.50	40.78	36.50
Nigeria: Bonny (37)	E3.31	E13.66	E10.85	12.70	14.31	14.31	14.80	29.97	40.00	36.50
FAR EAST AND OCEANIA										
Indonesia: Mines (34)	3.73	10.80	12.60	12.80	13.55	13.55	13.90	27.50	35.00	35.00

[a] No significant volume of exports.
[b] FOB equivalent.
E = Estimated.
Source: 1981 International Energy Annual, US Dept. of Energy, Energy Information Agency (1982).

TABLE E.III. IMPORTED COAL PRICES

Component	Price (US $/t)
Price FOB mine	28–43
Mine to port	7–20
Price FOB port	43–58
Port loading	1–2
Ocean freight	7–25
Port unloading	1–2
Delivered price	58–84
Delivered energy price	2.33–2.88 US $/$10^9$ J

Source: World Energy Outlook, International Energy Agency, Paris (1982).

TABLE E.IV. TYPICAL NATURAL GAS TRANSPORT COSTS

Component	Incremental cost (US $/$10^9$ J)	
	Pipeline	Liquefied natural gas
Gas gathering	0.24	0.24
Liquefaction	–	1.04
Transport	1.45	0.52–1.37
Regasification	–	0.38
Total incremental cost	1.69	2.18–3.03

Note: These costs must be added to the well-head charge.
Source: World Energy Outlook, International Energy Agency, Paris (1982).

TABLE E.V. TYPICAL NUCLEAR FUEL COSTS

Component	Unit	Cost (1982 US \$) Range	Reference value
Natural uranium	\$/kg U_3O_8	40–90	55
Conversion to UF_6, LWR	\$/kg U	5–8	6
Enrichment, LWR	\$/SWU	100–160	140
Fabrication and shipping of fresh fuel:			
LWR	\$/kg U	150–200	175
HWR	\$/kg U	50–100	70
Back-end cost (net)	\$/kg U	300–900	500

Appendix F

NUCLEAR FUEL CYCLE COST

F.1. THE FUEL CYCLE

The fuel cycle cost is the second most important item (after capital investment) in the determination of unit energy costs of a nuclear power plant. Unlike fossil plants, for which fuel costs comprise the major cost component of total generation costs, the cost of the fuel cycle in an LWR represents a relatively small percentage of the total generation cost, and the cost of the nuclear raw material itself (natural U_3O_8) accounts for only a portion of the nuclear fuel cycle cost. For an HWR, the contribution of the fuel cycle cost to the total generation cost of the plant is even less.

As shown in Fig.F.1 for an LWR, the fuel cycle cost components are:

- The price of yellowcake (natural U_3O_8), which is a function of extraction costs and market factors;
- Conversion of U_3O_8 to UF_6;
- Enrichment to the appropriate level in ^{235}U (usually in the range of 2.0–3.5%);
- Fuel element fabrication;
- Shipping to the nuclear reactor site;
- Irradiation of the fuel loaded into the reactor;
- Shipping and reprocessing spent fuel for recovery of unburned ^{235}U and fissile plutonium;
- Final disposal of radioactive wastes.

As an alternative, spent fuel is temporarily stored in spent fuel pools at the reactor site for eventual reprocessing or disposal.

Similarly, Fig.F.2 depicts the fuel cycle steps for an HWR. Yellowcake is converted to UO_2, fabricated into fuel elements out of compacted and sintered pellets and shipped to the reactor site.

The steps leading up to reactor irradiation are referred to as the *front end* of the fuel cycle and those after reactor irradiation as the *back end* of the fuel cycle.

F.2. NATURAL URANIUM PRICE TREND

The price of yellowcake has undergone large fluctuations in the recent past. This had many causes. In the early 1970s, it was expected that the growth of nuclear power would proceed rapidly, with a corresponding high growth in demand for uranium in proportion to available reserves and production capacity. In anticipation of that trend, the suppliers of uranium instituted a series of increases in the

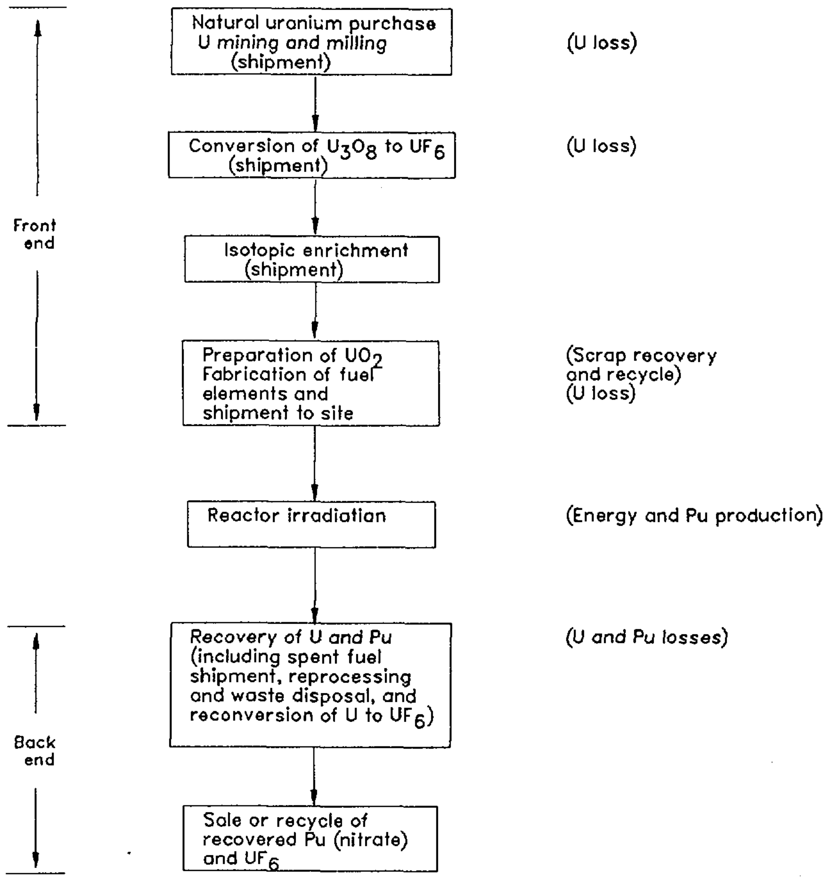

FIG.F.1. Generalized schematic diagram of LWR fuel cycle.

price of yellowcake. Price increases were further stimulated by the oil embargo of 1973 and the subsequent sharp increases in oil prices. When, later in the decade, it was realized that the number of nuclear power plant installations world wide was much below earlier expectations and uranium production capacity was in excess of demand, a softness in the price of uranium developed that turned into a rather precipitous drop after 1980.

Figure F.3 depicts the spot price of U_3O_8 from the late 1960s to the early 1980s. The price was held more or less constant in current currency until 1973 at about US \$15/kg (~US \$7/lb), followed by a steep rise to about US \$97/kg (US \$44/lb) where it stabilized for a couple of years until the price collapsed to about US \$53/kg (~US \$24/lb) in early 1982, with downward pressures still strong owing to market over-supply. Prices recovered somewhat in late 1982

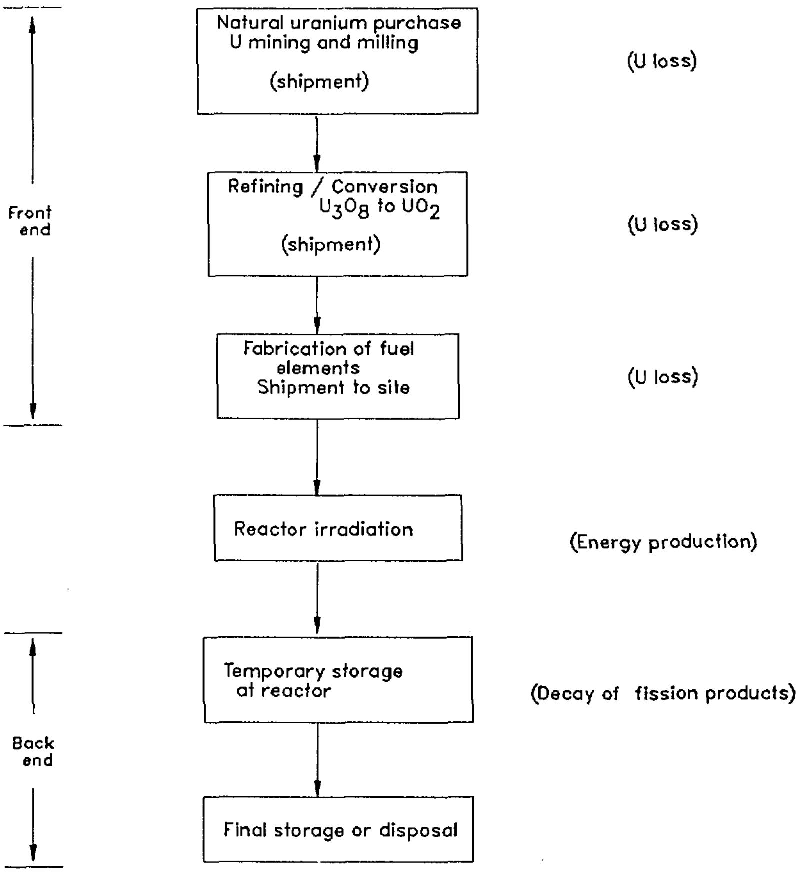

FIG.F.2. Generalized schematic diagram of HWR fuel cycle.

and 1983. In terms of constant 1980 US dollars, the price fluctuations seem larger, reaching a relative peak in 1977 and a relative low in 1982.

As a result of these developments, the price of yellowcake, which was the dominant component in the overall fuel cycle cost as recently as the late 1970s, is now of less importance, and enrichment costs dominate the overall picture. However, this situation may change again.

F.3. ENRICHMENT SERVICES PRICE TREND

Enrichment services price increases outpaced inflation on both sides of the Atlantic. A major factor here was undoubtedly the cost of energy needed to run

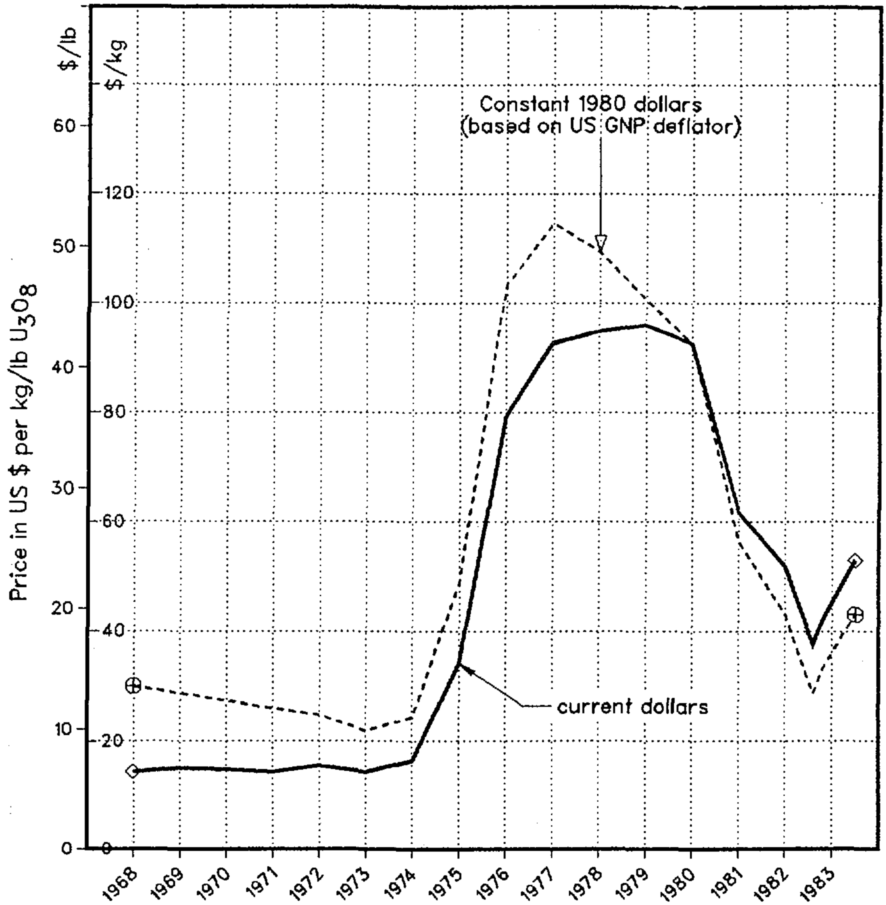

FIG.F.3. Uranium transaction values.

the gaseous diffusion plants. Another factor was a shift in US Government policy to recover fully the costs of enrichment services provided to utilities. Recent developments, however, point to stable prices in constant currency in the short term and possibly to a downward trend in the medium term owing to over-capacity, increased competition and technological advances.

Figure F.4 shows the price change in uranium enrichment services in the USA from 1970 to 1982 in both current and 1980 dollars.

F.4. UNIT FUEL CYCLE COSTS

Table F.I lists the various components of the nuclear fuel cycle along with unit prices as they have evolved during the past years. Three representative years

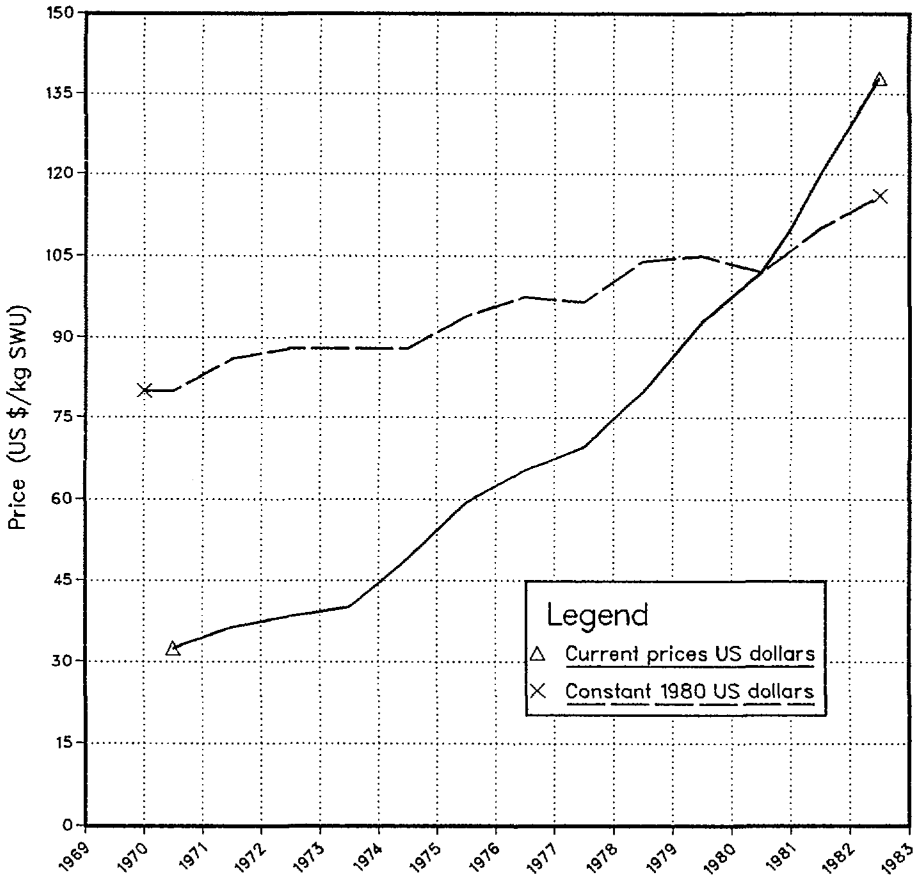

FIG.F.4. Enrichment service price (USA fixed commitment contracts).

are shown: one in 1973, prior to the uranium price increase; one in 1978 when U_3O_8 prices were at their peaks; and the price in 1982. The prices given are in round numbers and the intention is to show price evolution. The last column indicates recent price fluctuations due to international competition and other market forces at work on a worldwide basis. The table shows that there have been major increases in costs for almost every other component of the fuel cycle except uranium.

There is at present no free market for plutonium or ^{233}U by-products from nuclear power plants. The price of these products is therefore subject to speculation but can be inferred from considerations based on the recovery cost method or the economic indifference value method, in which it is reasoned that the price of the fissile materials in the long term will stabilize at such a level that

TABLE F.I. UNIT NUCLEAR FUEL CYCLE COST TRENDS
(Current cost values)

	Unit	1973	1978	1982	Recent range 1980–1984
LWR:					
Yellowcake (U_3O_8)	US $/kg	15	97	55	40–90
Conversion	US $/kg	3	4	6	5–8
Enrichment	US $/SWU	32	100	140	100–160
Fabrication and shipping (fresh fuel)	US $/kg	80	160	175	150–200
Back end cost	US $/kg	40	300	500	300–900
Uranium credit	US $/kg	28	178	180	160–200
Plutonium credit	US $/g	10	35	35	10–50
PHWR:					
Yellowcake (U_3O_8)	US $/kg			55	40–90
Refining/conversion	US $/kg			7	5–15
Fabrication and shipping (fresh fuel)	US $/kg			70	50–100
Back end cost	US $/kg			100	50–150

the total power generation costs of the alternative fuel cycle options will be 'indifferent' (i.e. the same).

F.5. FUEL CYCLE COST CALCULATIONS[1]

For demonstration purposes, two sample hand calculations are presented: one for an LWR and the other for an HWR, based on a given set of parameters. These same parameters will be subsequently employed to run an LWR case using the FUELCASH computer code.

In the operation of an LWR plant, a quantity of natural uranium ore many times the amount that will eventually be loaded into the reactor must be mined, milled and converted to U_3O_8. After the fuel is loaded into the reactor and commercial operation ensues, a portion of that fuel (usually 1/3 to 1/4) must be

[1] US $ are used throughout this section.

TABLE F.II. TECHNICAL ASSUMPTIONS FOR FUEL CYCLE COST: EQUILIBRIUM CORE

Reactor type	PWR
Reactor power	1876 MW(th)
Reactor power (electrical)	626 MW(e)
Initial enrichment	3.4% U-235
Final enrichment	0.95% U-235
Diffusion plant tails enrichment	0.25% U-235
Burnup	33 MW·d(th)/kg U
Reload scheme	1/3 core
Batch heavy metal reload (initial)	16 400 kg
Batch heavy metal reload (final)	15 683 kg
Plant capacity factor	70%
Losses:	
Conversion	1%
Fabrication	1%
Reconversion	1.5%
U and Pu credit	1.5%
Lead times (before fuel loading):	(Years)
Natural uranium purchase	3.0
Conversion	2.5
Enrichment	2.0
Fabrication	1.0
Lag times (after fuel discharge):	
Spent fuel cooling	1.0
Reprocessing	1.5
U and Pu credit	2.0

taken out and replaced by new fuel. When this process has been repeated two or three times, some sort of dynamic equilibrium is reached in which each batch removed from or loaded into the reactor core is essentially the same as that of the preceding or ensuing cycle.

Tables F.II and F.III give the technical assumptions on which these calculations are based together with the reference economic values for 1982 given in Table F.I.

Lead times refer to time periods before fuel was loaded into the reactor; lag times refer to time periods after the fuel has been removed from the reactor. The values shown are not to be taken as applicable to all situations but rather as representative numbers appropriate for a developing country.

F.5.1. Cost of the equilibrium fuel cycle of an LWR

For the equilibrium cycle, costs are calculated as follows:

A. FRONT END DIRECT COSTS

(a) Natural uranium costs

$$\frac{F}{P} = \frac{x_p - x_t}{x_f - x_t} = \frac{0.034 \quad - 0.0025}{0.00711 - 0.0025} = 6.833$$

where x_p is the enrichment of product in ^{235}U,
x_f is the enrichment of feed in ^{235}U,
x_t is the enrichment of tails in ^{235}U.

Assuming losses of 1% each in the conversion and fabrication processes:

(16 400 kg U) × (1.1793 kg U_3O_8/kg U) × $(1.01)^2$ × (F/P) × (\$55/kg U_3O_8)

= (134 797 kg U_3O_8) × (\$55/kg U_3O_8)

= \$7 413 800

or \$452/kg U loaded

(b) Conversion costs

(16 400 kg U) × (6.833) × $(1.01)^2$ × (\$6/kg U) = \$685 900

or \$42/kg U loaded

(c) Enrichment costs

The units of separative work per kg of enriched uranium product (P) as UF_6 is given by the formula:

$$\frac{SWU}{P} = V(x_p) - V(x_t) + \frac{F}{P}\,(V(x_t) - V(x_f))$$

$$V(x) = (2x - 1)\ \ln(x/(1 - x))$$

where V(x) is the 'value function' at the enrichment fraction x. This results in:

$x_p = 0.034$ $\qquad V(x_p) = 3.11922$
$x_f = 0.00711$ $\qquad V(x_f) = 4.86888$
$x_t = 0.0025$ $\qquad V(x_t) = 5.95902$

$$\frac{SWU}{P} = 4.609$$

Thus, the cost of the enrichment process, assuming a 1% fabrication loss, is:

(16 400 kg U) × (1.01) × (4.609 kg SWU/kg U) × ($140/kg SWU)

= (76 343.5) × (140) = $10 688 100

or $652/kg U loaded

(d) Fabrication and shipping costs of fresh fuel

(16 400 kg U) × ($175/kg U) = $2 870 000

or $175/kg U loaded

(e) Direct front end costs

The total cost for the front end of the LWR equilibrium cycle comes to:

	$
Natural uranium	7 413 800
Conversion	685 900
Enrichment	10 688 100
Fabrication and shipping (fresh fuel)	2 870 000
Direct front end costs	21 657 800

(f) Electricity generation

The amount of electricity generated by each equilibrium batch of 1/3 core is given by:

(33 MW·d/kg) × (16 400 kg) × (24 000 kW·h(th)/MW·d) × (626 MW(e)/1876 MW(th))

= 4.334×10^9 kW·h(e)

(g) Direct front end unit costs

Thus the front end direct fuel cycle costs in mills/kW·h are given by:

$$\frac{\$21\,657\,800 \times 10^3 \text{ mills/\$}}{4.334 \times 10^9} = 4.997 \text{ mills/kW·h(e)}$$

The direct unit energy cost for each step of the front end in the fuel cycle is shown in Table F.IV.

B. BACK END DIRECT COSTS

The back end of the fuel cycle in some countries, such as Canada and the USA, at present involves temporary storage of spent fuel on site for relatively long periods of time (tens of years), until permanent disposal at government control facilities or reprocessing when it becomes commercially available.

Other countries, such as France and the United Kingdom, have implemented the reprocessing route and in this case the direct back end costs of the equilibrium fuel cycle are obtained as follows:

(a) Reprocessing costs

The reference value of \$500/kg given in Table F.I for 'back end cost' includes spent fuel shipping, reprocessing, reconversion of recovered uranium and plutonium, and disposal costs. This value is quite speculative. Recent (1983) prices indicate a figure in the range of \$800–1000/kg. Thus, the overall back end costs are calculated to be:

(15 683 kg U) × (\$500/kg) = \$7 841 000

(b) Credits

In general, the irradiated fuel which is unloaded from an LWR contains bred fissile plutonium and unburned uranium with a ^{235}U concentration higher than that in natural uranium. Both these materials have value for re-use as fuel materials. This value is reflected as a fuel cycle credit in fuel cycles utilizing the reprocessing option. For the recovered uranium, the credit results from reductions in both requirements for natural uranium (F) and for separative work (SWU). The calculation of the credit per kg of recovered uranium (R) is shown below:

TABLE F.III. TECHNICAL ASSUMPTIONS FOR HWR FUEL CYCLE COST: EQUILIBRIUM CORE

Reactor type	CANDU-PHWR
Reactor power (thermal)	2156 MW(th)
Reactor power (electrical)	629 MW(e)
Refuelling system	On-line refuelling
Initial enrichment (U-235)	0.711%
Fuel bundles in core	4560
U weight in each bundle	18.8 kg
Burnup (equilibrium)	7.3 MW·d(th)/kg U
Plant capacity factor	80%
Batch approximation to on-line refuelling:	
Batch size	1/4 core
Initial mass of U in batch	21 432 kg
Final mass of U in batch (equilibrium)	21 174 kg
Losses:	
Refining/conversion	1%
Fabrication	1%
Lead times (before fuel loading):	(Years)
Natural uranium purchase	2.0
Refining/conversion	1.5
Fabrication	1.0
Lag times (after fuel discharge):	
Spent fuel cooling	3.0

(i) Feed credit

$$\frac{F}{R} = \frac{x_R - x_t}{x_f - x_t} =$$ natural uranium feed equivalent per kg of recovered uranium (R) at enrichment x_R

(ii) Separative work credit

$$\frac{SWU}{R} = V(x_R) - V(x_t) + \frac{F}{R}\,(V(x_t) - V(x_f))$$

= separative work credit per kg of recovered uranium (R) at enrichment x_R

With the parameters listed in Tables F.I and F.II, the calculation results in the following:

$x_R = 0.0095$	$V(x_R) = 4.55863$
$x_f = 0.00711$	$V(x_f) = 4.86888$
$x_t = 0.0025$	$V(x_t) = 5.95902$
$\frac{F}{R} = 1.51844$	$\frac{SWU}{R} = 0.2549$

The total credit (C) per kg of recovered uranium (R) is then given by:

$$\frac{C}{R} = \frac{F}{R} \times \$/\text{kg nat. U} + \frac{SWU}{R} \times \frac{\$}{SWU}$$

$$\$/\text{kg nat. U} = (\$55/\text{kg } U_3O_8)\,(1.1793 \text{ kg } U_3O_8/\text{kg nat. U})$$

$$= \$64.86/\text{kg nat. U}$$

Thus:

$$\frac{C}{R} = (1.51844)\,(64.86) + (0.2549)\,(140) = \$134.2/\text{kg U}$$

(iii) Conversion credit

There is also a corresponding conversion credit, since it was assumed that the uranium is recovered as UF_6:

$$(1.51844)\,(1.01)\,(\$6/\text{kg U}) = \$9.2/\text{kg U}$$

for a total credit of \$143.4 per kg of recovered uranium, or

$(15\ 683) \times (143.4) = \$2\ 248\ 942$

(iv) Plutonium credit

The recovered fissile plutonium amounts to:

(15 683 kg U) (0.007 kg Pu/kg U) (1/1.015) = 108.16 kg Pu

Based on a Pu indifference value of \$35/g, the plutonium credit amounts to \$3 785 600.

(c) Direct back end costs

The direct back end costs thus become

	\$
Reprocessing	7 841 500
U credit	(2 248 900)
Pu credit	(3 785 600)
Direct back end costs	1 807 000

(d) Direct back end unit costs

$$\frac{1\ 807\ 000 \times 10^3 \text{ mills/\$}}{4.334 \times 10^9 \text{ kW·h}} = 0.42 \text{ mills/kW·h(e)}$$

It must be emphasized that the costs for the back end of the fuel cycle are considered to be quite speculative.

C. *INDIRECT COSTS*

The calculation of indirect costs, or fuel cycle carrying charges, depends on the present worth discount rate (assumed 10% in this example) and the time an expenditure or credit is incurred relative to a reference time (usually taken as the start of the fuel cycle). For front end steps, these are the lead times shown in Table F.II. For back end steps, the in-core residence time of the batch must be added to the lag times which are measured from the end of irradiation given in Table F.II.

For a 70% capacity factor, the in-core residence time of each equilibrium batch is given by:

$$\frac{16\,400 \text{ kg/batch (33 MW·d/kg)}}{\frac{1}{3} \times 1876 \text{ MW(th)} \times 0.70} = 1236.37 \text{ days} = 3.4 \text{ years}$$

Using continuous discounting techniques, the present worth factor for the energy generated is given by:

$$\frac{1 - e^{-j \times 3.4}}{j \times 3.4} = 0.8541$$

The present worth value for each expenditure (or credit) is given by:

$$\text{PWR} = \frac{C_i}{(1 + i)^n} = e^{-jn}\, C_i = (\text{PW})C_i$$

where:

C_i is the cost (or credit) of a given time
n is the time in years from start of fuel cycle
$j = \ln(1 + i)$ = continuous discount rate $= \ln(1.1) = 0.0953$
i is the discount rate (10%/a)

The present worth factors included in Table F.IV are obtained by dividing PW by the present worth factor for the energy generated. These factors are then multiplied by the corresponding direct cost of each step or item in the fuel cycle process to obtain the total fuel cost per item. Indirect costs are then calculated by subtracting direct costs from total costs. Table F.IV shows the results for each step in the fuel cycle.

F.5.2. Cost of the equilibrium fuel cycle of a PHWR

This section includes a calculation of the fuel cycle cost of a pressurized heavy-water reactor (PHWR) in the equilibrium cycle, using the same approach as described above for an LWR. The basic unit costs assumed for this calculation are indicated in Table F.I. Table F.III lists the technical assumptions required for the calculation.

TABLE F.IV. EQUILIBRIUM FUEL CYCLE COSTS (626 MW(e) PWR)

	(1) Direct cost (mills/kW·h)	(2) Years from start of fuel cycle	(3) Present worth factor	4 = (1) X (3) Total costs (mills/kW·h)	5 = (4) − (1) Indirect costs (mills/kW·h)
Yellowcake (U_3O_8)	1.711	−3.0	1.558	2.666	0.955
Conversion	0.158	−2.5	1.486	0.235	0.077
Enrichment	2.465	−2.0	1.417	3.493	1.028
Fabrication and shipping (fresh fuel)	0.662	−1.0	1.288	0.853	0.191
Front end costs	4.996			7.247	2.251
Reprocessing	1.809	4.9	0.734	1.328	−0.481
Uranium credit	−0.519	5.4	0.700	−0.363	0.156
Plutonium credit	−0.873	5.4	0.700	−0.611	0.262
Back end costs	0.417			0.354	−0.063
Total costs	5.413			7.601	2.188

A. *DIRECT COSTS*

(a) *Front end costs*

Starting with the amount of natural uranium loaded as a batch into the reactor, one works backwards to arrive at the complete front end direct costs (numbers are rounded off to the nearest hundred dollars):

(i) Fabrication and shipping costs of fresh fuel

21 432 kg X \$70/kg = \$1 500 200

The loss factor of 1% is considered in the assumed price of the finished product.

(ii) Refining/conversion costs

21 432 kg X $(1.01)^2$ X \$7/kg = \$153 000

(iii) Yellowcake (U_3O_8) costs

$$21\,432 \text{ kg} \times (1.01)^2 \times (1.1793 \text{ kg } U_3O_8/\text{kg U}) \times \$55/\text{kg } U_3O_8$$

$$= \$1\,418\,100$$

(b) Back end costs

$$21\,174 \text{ kg} \times \$100/\text{kg} = \$2\,117\,400$$

(c) Total direct costs

	$
Yellowcake	1 418 100
Refining/conversion	153 000
Fabrication and shipping (fresh fuel)	1 500 200
Front end cost	3 071 300
Back end cost	2 117 400
	5 188 700

(d) Electricity generation by batch

$$(21\,432 \text{ kg}) \times (7.3 \text{ MW·d/kg}) \times (24\,000 \text{ kW·h(th)/MW·d}) \times (629 \text{ MW(e)}/2156 \text{ MW(th)})$$

$$= 1.0955 \times 10^9 \text{ kW·h(e) or approx. } 1.1 \times 10^9 \text{ kW·h(e)}$$

Alternatively:

$$1/4 \times 629 \times 10^3 \text{ kW(e)} \times 363 \text{ days per year} \times 24 \text{ hours per day} \times 0.8$$

$$= 1.0960 \times 10^9 \text{ kW·h(e)}$$

$$\cong 1.1 \times 10^9 \text{ kW·h(e)}$$

The figure of 363 days per year refers to the average in-core residence time (see next section on indirect costs for its derivation).

TABLE F.V. EQUILIBRIUM FUEL CYCLE (629 MW(e) PHWR)

	Direct cost (mills/kW·h)	Indirect cost (mills/kW·h)	Years from start of fuel cycle	Total costs (mills/kW·h)
Yellowcake	1.289	0.346	−2.0	1.635
Refining/conversion	0.139	0.029	−1.5	0.168
Fabrication/shipping (fresh fuel)	1.364	0.209	−1.0	1.573
	2.792	0.584		3.376
Disposal	1.925	−0.547	4.0	1.378
Total	4.717	0.037		4.754

(e) Direct unit costs

Front end $\dfrac{3\,071\,300 \times 10^3 \text{ mills}}{1.1 \times 10^9 \text{ kW·h}} = 2.792 \text{ mills/kW·h}$

Back end $\dfrac{2\,117\,400 \times 10^3 \text{ mills}}{1.1 \times 10^9 \text{ kW·h}} = 1.925 \text{ mills/kW·h}$

Total 4.717 mills/kW·h

The direct unit costs for each step in the fuel cycle are shown in Table F.V.

B. *INDIRECT COSTS*

Based on the technical assumptions of Table F.III, the in-core residence time is:

$$\frac{(21.432 \text{ kg})\ (7.3 \text{ MW·d/kg})}{\frac{1}{4} \times 2156 \text{ MW(th)} \quad (0.80)} = 363 \text{ days} \approx 1 \text{ year}$$

The present worth factor (PWF) for the energy generated based on one year of in-core residence time and using continuous discounting is given by:

$$\frac{1 - e^{-j \times 1.0}}{j \times 1.0} = 0.954$$

where $j = \ln(1 + i)$ = continuous discount rate = $\ln(1.1) = 0.0953$, and i is the discount rate, assumed as 10% per annum in this example.

(a) Yellowcake indirect costs

The total cost of U_3O_8, using the same approach as for the LWR calculation described above, is:

$$\frac{1\,418\,100 \times 10^3}{(1.1)^{-2} \times 1.1 \times 10^9 \times 0.954} = 1.635 \text{ mills/kW·h}$$

The indirect cost is:

Total cost minus direct cost = 1.635 − 1.289 = 0.346 mills/kW·h

(b) Other items

Other items in the fuel cycle can be calculated as above. Table F.V gives the results for each item.

F.6. FUELCASH COMPUTER CODE

A more sophisticated calculation of nuclear fuel cycle costs can be carried out by means of the FUELCASH-II computer code. This code is described in detail in IAEA Technical Report No. 175, Economic Evaluation of Bids for Nuclear Power Plants (1976). It was developed jointly by the Comisión Federal de Electricidad (CFE) of Mexico and NUS Corp. of the USA especially for planning studies and nuclear fuel evaluation. Costs are calculated in a manner similar to that described for the equilibrium core, although each fuel batch is treated individually. The present worth value of each expenditure and credit over the assumed 30 year life of the reactor is estimated and summed to find the direct costs and levelized total costs. To illustrate the use of FUELCASH, a computer run was made using the same input data as given in Tables F.I and F.II for an LWR. The main results of this run are summarized in Table F.VI. Some of the output from the program is shown in Tables F.VII to F.XII given at the end of this chapter.

TABLE F.VI. NUCLEAR FUEL CYCLE COST ESTIMATE (626 MW(e) PWR): SUMMARY RESULTS OF THE FUEL CYCLE COST (FUELCASH COST RESULTS)

ITEMS	DIRECT (MILLS/KWHE)	INDIRECT (MILLS/KWHE)	TOTAL (MILLS/KWHE)	% OF TOTAL
NATURAL U	1.791	0.928	2.719	34.9
CONVERSION	0.164	0.091	0.255	3.3
ENRICHING	2.561	0.940	3.501	44.9
FABRICATION	0.718	0.208	0.926	11.9
INITIAL PU	0.0	0.0	0.0	0.0
SHIPPING	0.0	0.0	0.0	0.0
REPROCESSING	1.938	-0.470	1.468	18.8
U CREDIT	-0.565	0.145	-0.420	-5.4
PU CREDIT	-0.928	0.273	-0.654	-8.4
LEVELIZED	5.680	2.115	7.795	100.0

(CUM. PER CENT:100.0)

VARIABLE FUEL COST (C/1.0E+6 KCAL) = 220.96460

FIXED FUEL COST ($ / KWE) = 132.36189

TABLE F.VII. NUS/CFE FUELCASH-II NUCLEAR FUEL COMPUTER CODE INPUT DATA SUMMARY: NUCLEAR FUEL CYCLE COST ESTIMATE (626 MW(e) PWR)

REACTOR START DT. DAY/MO/YR	END OF STUDY DT. DAY/MO/YR	THERMAL POWER MWT,	PRESENT WORTH FACTOR	PRES.WOR. START DT. DAY/MO/YR
0 1 1982	0 1 2012	1876.00	0.10000	0 1 1982

LIBRARY CHANGES ARE SHOWN BELOW BY ITEM NO. AND NEW VALUE

5	1.0100	8	1.0100	9	10200.0000	10	10410.0000	11	11225.0000
12	45.0000	14	0.5000						

30 NEW SETS OF SYSTEM DATA

EFF. DATE DAY/MO/YR	HEAT RATE (OR MWE)	CAPACITY FACTOR
0 1 1982	10200.0000	0.6000
0 1 1983	10200.0000	0.7040
0 1 1984	10200.0000	0.7582
0 1 1985	10200.0000	0.8123
0 1 1986	10242.0000	0.8156
0 1 1987	10242.0000	0.8156
0 1 1988	10242.0000	0.8156
0 1 1989	10242.0000	0.8156
0 1 1990	10242.0000	0.8156
0 1 1991	10242.0000	0.8156
0 1 1992	10242.0000	0.8156
0 1 1993	10242.0000	0.8156
0 1 1994	10242.0000	0.8156
0 1 1995	10242.0000	0.8156
0 1 1996	10242.0000	0.8156
0 1 1997	10259.0000	0.7904
0 1 1998	10276.0000	0.7655
0 1 1999	10292.0000	0.7454
0 1 2000	10309.0000	0.7254
0 1 2001	10326.0000	0.7056
0 1 2002	10355.0000	0.6825
0 1 2003	10384.0000	0.6597
0 1 2004	10413.0000	0.6371
0 1 2005	10442.0000	0.6148
0 1 2006	10470.0000	0.5928
0 1 2007	10499.0000	0.5711
0 1 2008	10540.0000	0.5503
0 1 2009	10586.0000	0.5309
0 1 2010	10671.0000	0.5047
0 1 2011	10736.0000	0.4789

1 NEW COST SETS FOR ALL ASSEMBLIES

EFF. DATE DAY/MO/YR	U3O8 $/LB	U3O8-UF6 CONV.$/KGU	ENRICH. $/KGU	TAILS OPT=0	PU $/GM OR FRAC.	FAB. $/KGH	SHIPPING $/KGHI	REPRO.$/ DAY-/KGHF	RECONV.TO UF6-$/KGU
0 1 1979	25.00	6.00	140.00	0.00250	35.0000	175.00	0.0	490.00	8.00

TABLE F.VIII. TOTAL NUMBER OF BATCHES: SUMMARY OF TOTAL EXISTING (OR NEW) BATCH INPUT DATA

BATCH NO.	INSTALLED AT START CYCLE NO.	REMOVED AT END CYCLE NO.	CORE NO.	ASSY TYP NO.	NO. CYCLES INC.NO	TOTAL BATCH BURNUP (MWD/MTH)	INIT. MASS (MTH)	INIT. U ENRICH. FRACTION	FINAL MASS (MTH)	FINAL U ENRICH. FRACTION	INIT.PU (FISSILE) (KG)	FIN.PU (FISSILE) (KG)
1	1	1	1	1	1	16510.00	16.4000	0.022700	16.0105	0.009700	0.0	85.2800
2	1	2	1	1	2	26650.00	16.4000	0.030300	15.8260	0.010200	0.0	103.3200
3	1	3	1	1	3	31840.00	16.4000	0.034000	15.7030	0.010000	0.0	108.2400
4	2	4	2	2	3	30310.00	16.4000	0.034000	15.7235	0.010400	0.0	108.2400
5	3	5	2	2	3	32120.00	16.4000	0.034000	15.7030	0.009900	0.0	108.2400
6	4	6	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
7	5	7	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
8	6	8	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
9	7	9	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
10	8	10	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
11	9	11	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
12	10	12	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
13	11	13	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
14	12	14	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
15	13	15	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
16	14	16	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
17	15	17	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
18	16	18	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
19	17	19	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
20	18	20	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
21	19	21	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
22	20	22	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
23	21	23	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
24	22	24	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
25	23	25	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
26	24	26	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800
27	25	27	2	2	3	33000.00	16.4000	0.034000	15.6825	0.009500	0.0	109.8800

TABLE F. IX. NEW LAG* AND LEAD TIMES

EFF. DATE DAY/MO/YR	DISCH. TO REPROCESS	DISCH.TO SHIPPING	DISCH. TO PU CREDIT	DISCH. TO UR.CREDIT
0 1 1980	1.5000	1.0000	2.0000	2.0000

1 NEW FABRICATION LEAD TIME SETS FOR ALL ASSEMBLIES (IN YEARS PRIOR TO CHARGE DATE)

EFF. DATE DAY/MO/YR	BEGIN PAY MENTS-T1	END PROG PAYTS-T2	FINAL PAY IF ANY-T3	FRACTION PAID AT T2
0 1 1980	2.0000	1.5000	1.0000	0.0

1 NEW NATURAL URANIUM LEAD TIME SETS (IN YEARS PRIOR TO CHARGE DATE)

EFF. DATE DAY/MO/YR	BEGIN PAY MENTS-T1	END PROG PAYTS-T2	FINAL PAY IF ANY-T3	FRACTION PAID AT T2	ENRICHED U LOSS FACTOR
0 1 1978	4.0000	3.5000	3.0000	0.0	0.0

1 NEW ENRICHING LEAD TIME SETS (IN YEARS PRIOR TO CHARGE DATE)

EFF. DATE DAY/MO/YR	BEGIN PAY MENTS-T1	END PROG PAYTS-T2	FINAL PAY IF ANY-T3	FRACTION PAID AT T2
0 1 1977	5.0000	3.0000	2.0000	0.0

* Lag times in years from discharge.

TABLE F.X. NUS/CFE FUELCASH-II RESULTS: NUCLEAR FUEL CYCLE COST ESTIMATE (626 MW(e) PWR)

CYCLE NO.	START DATE DAY/MO/YEAR	END DATE DAY/MO/YEAR	CYCLE LENGTH	OPERATION DAYS	ENERGY KW-HR	THERMAL ENERGY BTU	PRESENT WORTH ENERGY KW-HR	CUM.TOT.PRES. WORTH KW-HR
1	0 1 1982	20 8 1983	642.0	597.0	5.7595E+9	5.8747E+13	5.3326E+9	5.3326E+9
2	4 10 1983	20 9 1984	397.0	352.0	3.9486E+9	4.0276E+13	3.1902E+9	8.5229E+9
3	4 11 1984	26 9 1985	371.0	326.0	3.9427E+9	4.0216E+13	2.8818E+9	11.4047E+9
4	10 11 1985	30 10 1986	399.0	354.0	4.3316E+9	4.4338E+13	2.8635E+9	14.2682E+9
5	14 12 1986	3 12 1987	399.0	354.0	4.6742E+9	4.7873E+13	2.7842E+9	17.0524E+9
6	17 1 1988	5 1 1989	399.0	354.0	4.3316E+9	4.4364E+13	2.3248E+9	19.3772E+9
7	19 2 1989	7 2 1990	398.0	353.0	4.3193E+9	4.4238E+13	2.0898E+9	21.4669E+9
8	24 3 1990	13 3 1991	399.0	354.0	4.3316E+9	4.4364E+13	1.8885E+9	23.3555E+9
9	27 4 1991	15 4 1992	399.0	354.0	4.3316E+9	4.4364E+13	1.7017E+9	25.0571E+9
10	30 5 1992	19 5 1993	399.0	354.0	4.3316E+9	4.4364E+13	1.5335E+9	26.5906E+9
11	3 7 1993	21 6 1994	398.0	353.0	4.3193E+9	4.4238E+13	1.3783E+9	27.9689E+9
12	5 8 1994	25 7 1995	399.0	354.0	4.3316E+9	4.4364E+13	1.2455E+9	29.2144E+9
13	8 9 1995	27 8 1996	399.0	354.0	4.3316E+9	4.4364E+13	1.1223E+9	30.3367E+9
14	11 10 1996	8 10 1997	407.0	362.0	4.3177E+9	4.4278E+13	1.0072E+9	31.3439E+9
15	22 11 1997	3 12 1998	421.0	376.0	4.6396E+9	4.7669E+13	0.9715E+9	32.3154E+9
16	17 1 1999	9 2 2000	433.0	388.0	4.3052E+9	4.4317E+13	0.8064E+9	33.1218E+9
17	25 3 2000	0 5 2001	446.0	401.0	4.2981E+9	4.4331E+13	0.7178E+9	33.8396E+9
18	14 6 2001	4 8 2002	461.0	416.0	4.2875E+9	4.4336E+13	0.6363E+9	34.4758E+9
19	18 9 2002	25 11 2003	478.0	433.0	4.6163E+9	4.7905E+13	0.6061E+9	35.0819E+9
20	9 1 2004	10 4 2005	502.0	457.0	4.2609E+9	4.4395E+13	0.4922E+9	35.5741E+9
21	25 5 2005	15 9 2006	523.0	478.0	4.2349E+9	4.4283E+13	0.4281E+9	36.0022E+9
22	30 10 2006	19 3 2008	551.0	506.0	4.2239E+9	4.4357E+13	0.3711E+9	36.3733E+9
23	3 5 2008	19 10 2009	579.0	534.0	4.1873E+9	4.4283E+13	0.3175E+9	36.6908E+9
24	3 12 2009	6 7 2011	625.0	580.0	4.1497E+9	4.4350E+13	0.2690E+9	36.9598E+9
25	20 8 2011	13 4 2013	647.0	602.0	4.1262E+9	4.4299E+13	0.2265E+9	37.1863E+9

ENERGY RELEASED 108.9315E+9

LEVELIZED FUELCOST,MILLS/KWHE 7.794868

TABLE F.XI. NUCLEAR FUEL CYCLE COST ESTIMATE (626 MW(e) PWR): CALCULATION OF BATCH IN AND OUT DATES

BATCH NO.	--DATE IN--- DAY/MON/YEAR			--DATE OUT-- DAY/MON/YEAR		
1	0	1	1982	20	8	1983
2	0	1	1982	20	9	1984
3	0	1	1982	26	9	1985
4	4	10	1983	30	10	1986
5	4	11	1984	3	12	1987
6	10	11	1985	5	1	1989
7	14	12	1986	7	2	1990
8	17	1	1988	13	3	1991
9	19	2	1989	15	4	1992
10	24	3	1990	19	5	1993
11	27	4	1991	21	6	1994
12	30	5	1992	25	7	1995
13	3	7	1993	27	8	1996
14	5	8	1994	8	10	1997
15	8	9	1995	3	12	1998
16	11	10	1996	9	2	2000
17	22	11	1997	0	5	2001
18	17	1	1999	4	8	2002
19	25	3	2000	25	11	2003
20	14	6	2001	10	4	2005
21	18	9	2002	15	9	2006
22	9	1	2004	19	3	2008
23	25	5	2005	19	10	2009
24	30	10	2006	6	7	2011
25	3	5	2008	13	4	2013
26	3	12	2009	13	4	2014
27	20	8	2011	13	4	2015

TABLE F.XII. NUCLEAR FUEL CYCLE COST ESTIMATE (626 MW(e) PWR)
(Fuel cost and equivalent date of payment for each component in a batch)

BATCH	NATURAL U		CONVERSION		ENRICHING		FABRICATION	
NO.	DATE	TOT.$	DATE	TOT.$	DATE	TOT.$	DATE	TOT.$
1	79.000	4.717	78.749	0.431	80.000	5.532	81.000	2.899
CUM.CURRENT		4.717		0.431		5.532		2.899
CUM.PRS.WR.		6.279		0.588		6.694		3.189
2	79.000	6.492	78.749	0.593	80.000	8.887	81.000	2.899
CUM.CURRENT		11.209		1.025		14.419		5.797
CUM.PRS.WR.		14.920		1.397		17.447		6.377
3	79.000	7.356	78.749	0.672	80.000	10.582	81.000	2.899
CUM.CURRENT		18.566		1.697		25.001		8.696
CUM.PRS.WR.		24.711		2.313		30.252		9.566
4	80.759	7.356	80.507	0.672	81.759	10.582	82.759	2.899
CUM.CURRENT		25.922		2.369		35.584		11.595
CUM.PRS.WR.		32.991		3.088		41.080		12.262
5	81.844	7.356	81.593	0.672	82.844	10.582	83.844	2.899
CUM.CURRENT		33.278		3.042		46.166		14.493
CUM.PRS.WR.		40.457		3.787		50.844		14.694
6	82.860	7.356	82.608	0.672	83.860	10.582	84.860	2.899
CUM.CURRENT		40.634		3.714		56.749		17.392
CUM.PRS.WR.		47.234		4.422		59.708		16.901
7	83.953	7.356	83.702	0.672	84.953	10.582	85.953	2.899
CUM.CURRENT		47.990		4.386		67.331		20.291
CUM.PRS.WR.		53.341		4.994		67.694		18.889
8	85.046	7.356	84.795	0.672	86.046	10.582	87.046	2.899
CUM.CURRENT		55.347		5.059		77.914		23.190
CUM.PRS.WR.		58.843		5.509		74.890		20.681
9	86.137	7.356	85.885	0.672	87.137	10.582	88.136	2.899
CUM.CURRENT		62.703		5.731		88.496		26.088
CUM.PRS.WR.		63.803		5.973		81.376		22.296
10	87.227	7.356	86.976	0.672	88.227	10.582	89.227	2.899
CUM.CURRENT		70.059		6.403		99.078		28.987
CUM.PRS.WR.		68.272		6.391		87.221		23.752
11	88.320	7.356	88.069	0.672	89.320	10.582	90.320	2.899
CUM.CURRENT		77.415		7.076		109.661		31.886
CUM.PRS.WR.		72.300		6.768		92.488		25.063
12	89.412	7.356	89.161	0.672	90.412	10.582	91.412	2.899
CUM.CURRENT		84.771		7.748		120.243		34.784
CUM.PRS.WR.		75.929		7.108		97.235		26.245
13	90.504	7.356	90.256	0.672	91.504	10.582	92.504	2.899
CUM.CURRENT		92.128		8.421		130.826		37.683
CUM.PRS.WR.		79.200		7.414		101.512		27.311

INITIAL PU		SHIPPING		REPROCESSING		U CREDIT		PU CREDIT	
DATE	TOT.$	DATE	TOT.$	DATE	TOT.$	DATE	TOT.$	DATE	TOT.$
0.0	0.0	84.635	0.0	85.135	7.971	85.635	-2.375	85.635	-2.940
	0.0		0.0		7.971		-2.375		-2.940
	0.0		0.0		5.912		-1.679		-2.079
0.0	0.0	85.721	0.0	86.221	7.879	86.721	-2.607	86.721	-3.562
	0.0		0.0		15.850		-4.982		-6.502
	0.0		0.0		11.181		-3.342		-4.350
0.0	0.0	86.737	0.0	87.237	7.818	87.737	-2.483	87.737	-3.732
	0.0		0.0		23.668		-7.466		-10.234
	0.0		0.0		15.927		-4.779		-6.510
0.0	0.0	87.830	0.0	88.330	7.828	88.830	-2.695	88.830	-3.732
	0.0		0.0		31.496		-10.161		-13.965
	0.0		0.0		20.209		-6.185		-8.456
0.0	0.0	88.923	0.0	89.423	7.818	89.923	-2.432	89.923	-3.732
	0.0		0.0		39.314		-12.593		-17.697
	0.0		0.0		24.062		-7.328		-10.210
0.0	0.0	90.014	0.0	90.514	7.808	91.014	-2.225	91.014	-3.788
	0.0		0.0		47.121		-14.818		-21.485
	0.0		0.0		27.531		-8.270		-11.814
0.0	0.0	91.104	0.0	91.604	7.808	92.104	-2.225	92.104	-3.788
	0.0		0.0		54.929		-17.043		-25.273
	0.0		0.0		30.656		-9.120		-13.261
0.0	0.0	92.197	0.0	92.697	7.808	93.197	-2.225	93.197	-3.788
	0.0		0.0		62.736		-19.268		-29.061
	0.0		0.0		33.473		-9.885		-14.564
0.0	0.0	93.289	0.0	93.789	7.808	94.289	-2.225	94.289	-3.788
	0.0		0.0		70.544		-21.493		-32.849
	0.0		0.0		36.011		-10.575		-15.738
0.0	0.0	94.381	0.0	94.881	7.808	95.381	-2.225	95.381	-3.788
	0.0		0.0		78.352		-23.717		-36.637
	0.0		0.0		38.299		-11.196		-16.796
0.0	0.0	95.471	0.0	95.971	7.808	96.471	-2.225	96.471	-3.788
	0.0		0.0		86.159		-25.942		-40.425
	0.0		0.0		40.361		-11.756		-17.750
0.0	0.0	96.564	0.0	97.064	7.808	97.564	-2.225	97.564	-3.788
	0.0		0.0		93.967		-28.167		-44.213
	0.0		0.0		42.218		-12.261		-18.609
0.0	0.0	97.655	0.0	98.155	7.808	98.655	-2.225	98.655	-3.788
	0.0		0.0		101.775		-30.392		-48.002
	0.0		0.0		43.893		-12.716		-19.384

TABLE F.XII. (cont.)

BATCH NO.	NATURAL U DATE	NATURAL U TOT.$	CONVERSION DATE	CONVERSION TOT.$	ENRICHING DATE	ENRICHING TOT.$	FABRICATION DATE	FABRICATION TOT.$
14	91.594	7.356	91.346	0.672	92.594	10.582	93.594	2.899
CUM.CURRENT		99.484		9.093		141.408		40.582
CUM.PRS.WR.		82.148		7.690		105.368		28.271
15	92.687	7.356	92.436	0.672	93.687	10.582	94.687	2.899
CUM.CURRENT		106.840		9.765		151.991		43.480
CUM.PRS.WR.		84.804		7.939		108.841		29.136
16	93.778	7.356	93.527	0.672	94.778	10.582	95.778	2.899
CUM.CURRENT		114.196		10.438		162.573		46.379
CUM.PRS.WR.		87.198		8.163		111.972		29.915
17	94.893	7.356	94.642	0.672	95.893	10.582	96.893	2.899
CUM.CURRENT		121.552		11.110		173.155		49.278
CUM.PRS.WR.		89.351		8.365		114.787		30.616
18	96.046	7.356	95.795	0.672	97.046	10.582	98.046	2.899
CUM.CURRENT		128.909		11.782		183.738		52.177
CUM.PRS.WR.		91.279		8.545		117.310		31.244
19	97.232	7.356	96.980	0.672	98.232	10.582	99.232	2.899
CUM.CURRENT		136.265		12.455		194.320		55.075
CUM.PRS.WR.		93.002		8.706		119.562		31.805
20	98.452	7.356	98.200	0.672	99.452	10.582	0.452	2.899
CUM.CURRENT		143.621		13.127		204.903		57.974
CUM.PRS.WR.		94.535		8.850		121.568		32.305
21	99.714	7.356	99.463	0.672	0.714	10.582	1.715	2.899
CUM.CURRENT		150.977		13.799		215.485		60.873
CUM.PRS.WR.		95.895		8.977		123.346		32.747
22	1.024	7.356	0.773	0.672	2.024	10.582	3.024	2.899
CUM.CURRENT		158.333		14.472		226.068		63.771
CUM.PRS.WR.		97.095		9.090		124.915		33.138
23	2.397	7.356	2.146	0.672	3.397	10.582	4.397	2.899
CUM.CURRENT		165.690		15.144		236.650		66.670
CUM.PRS.WR.		98.148		9.188		126.292		33.481
24	3.830	7.356	3.578	0.672	4.830	10.582	5.830	2.899
CUM.CURRENT		173.046		15.817		247.232		69.569
CUM.PRS.WR.		99.066		9.274		127.493		33.780
25	5.338	7.356	5.087	0.672	6.338	10.582	7.338	2.899
CUM.CURRENT		180.402		16.489		257.815		72.467
CUM.PRS.WR.		99.862		9.349		128.533		34.039
26	6.923	7.356	6.671	0.672	7.923	10.582	8.923	2.899
CUM.CURRENT		187.758		17.161		268.397		75.366
CUM.PRS.WR.		100.546		9.413		129.428		34.262
27	8.635	7.356	8.384	0.672	9.635	10.582	10.635	2.899
CUM.CURRENT		195.114		17.834		278.979		78.265
CUM.PRS.WR.		101.127		9.467		130.188		34.451

TOTAL OF ALL PAYMENTS 0.61870E+03 MILLION DOLLARS

INITIAL PU		SHIPPING		REPROCESSING		U CREDIT		PU CREDIT	
DATE	TOT.$	DATE	TOT.$	DATE	TOT.$	DATE	TOT.$	DATE	TOT.$
0.0	0.0	98.770	0.0	99.270	7.808	99.770	-2.225	99.770	-3.788
	0.0		0.0		109.582		-32.617		-51.790
	0.0		0.0		45.398		-13.125		-20.080
0.0	0.0	99.923	0.0	0.423	7.808	0.923	-2.225	0.923	-3.788
	0.0		0.0		117.390		-34.842		-55.578
	0.0		0.0		46.747		-13.492		-20.704
0.0	0.0	1.109	0.0	1.609	7.808	2.109	-2.225	2.109	-3.788
	0.0		0.0		125.197		-37.067		-59.366
	0.0		0.0		47.951		-13.819		-21.261
0.0	0.0	2.329	0.0	2.829	7.808	3.329	-2.225	3.329	-3.788
	0.0		0.0		133.005		-39.292		-63.154
	0.0		0.0		49.024		-14.110		-21.757
0.0	0.0	3.592	0.0	4.092	7.808	4.592	-2.225	4.592	-3.788
	0.0		0.0		140.813		-41.517		-66.942
	0.0		0.0		49.975		-14.369		-22.197
0.0	0.0	4.901	0.0	5.401	7.808	5.901	-2.225	5.901	-3.788
	0.0		0.0		148.620		-43.742		-70.730
	0.0		0.0		50.814		-14.597		-22.585
0.0	0.0	6.274	0.0	6.774	7.808	7.274	-2.225	7.274	-3.788
	0.0		0.0		156.428		-45.967		-74.518
	0.0		0.0		51.550		-14.797		-22.926
0.0	0.0	7.707	0.0	8.207	7.808	8.707	-2.225	8.707	-3.788
	0.0		0.0		164.236		-48.192		-78.306
	0.0		0.0		52.193		-14.971		-23.223
0.0	0.0	9.215	0.0	9.715	7.808	10.215	-2.225	10.215	-3.788
	0.0		0.0		172.043		-50.417		-82.094
	0.0		0.0		52.749		-15.122		-23.480
0.0	0.0	10.800	0.0	11.300	7.808	11.800	-2.225	11.800	-3.788
	0.0		0.0		179.851		-52.642		-85.883
	0.0		0.0		53.227		-15.252		-23.702
0.0	0.0	12.512	0.0	13.012	7.808	13.512	-2.225	13.512	-3.788
	0.0		0.0		187.658		-54.867		-89.671
	0.0		0.0		53.633		-15.363		-23.890
0.0	0.0	14.282	0.0	14.782	7.808	15.282	-2.225	15.282	-3.788
	0.0		0.0		195.466		-57.092		-93.459
	0.0		0.0		53.977		-15.456		-24.048
0.0	0.0	15.282	0.0	15.782	7.808	16.282	-2.225	16.282	-3.788
	0.0		0.0		203.274		-59.317		-97.247
	0.0		0.0		54.289		-15.541		-24.193
0.0	0.0	16.282	0.0	16.782	7.808	17.282	-2.225	17.282	-3.788
	0.0		0.0		211.081		-61.542		-101.035
	0.0		0.0		54.572		-15.618		-24.324

PRESENT WORTH OF ALL PAYMENTS 0.28986E+03 MILLION DOLLARS

Appendix G

TYPICAL TECHNICAL DATA FOR ELECTRIC POWER PLANTS

The technical performance parameters of each of the generic electrical generation technologies indicate unique dependences on factors such as electrical capacity, type of steam cycle, coal type, pollution standards and site conditions. They can result in significant variations in performance parameters from country to country and from region to region in the same country. Typical values for several such parameters and their principal dependences on design characteristics are summarized below. These data are based on experience in the USA and represent an accumulation of the information found in Refs [1–7]. In actual system expansion studies it is recommended that site-specific information be used as far as is feasible and that the generalized values given in this appendix be used only when site-specific information does not exist.

G.1. NUCLEAR PLANTS

The data presented here for nuclear plants represent composites of BWR and PWR experience. Other types of nuclear-powered plants, including HWRs and GCRs, have been used by utilities throughout the world. For simplicity, however, only data from LWRs operating in the USA were used in determining these representative values. Current nuclear plants are usually in the range of 600–1200 MW of net electrical capacity. The recent general trend has been towards the high end of this range because of the economies of scale in the capital investment. However, other considerations such as small grid systems, improved system reliability, lower demand, lower growth expectations and cash flow considerations, might dictate that smaller units would be more appropriate in certain parts of the world.

The available data do not indicate a dependence of the technical parameters on the size of the nuclear power plant within the 600–1200 MW range. This observation is in contrast to the fossil-fired plants in the same size range, where, by and large, the reliability of the plants decreases with increasing plant capacity.

Typical data for nuclear LWR plants are shown in Table G.I. The planned outage rate (POR) in this table is defined in Section 6.3 and represents the correct parameter for maintenance requirements in a planning model such as WASP. The POR was derived from data given in Ref. [7], which shows a scheduled outage rate (SOR) of 0.192. Based on the definitions in Section 6.3 and a reported service to period hour ratio (SH/PH) of 0.704 (from Ref. [7]), the corresponding POR can be determined as follows:

TABLE G.I. TYPICAL TECHNICAL DATA FOR NUCLEAR LWR POWER PLANTS

Size (MW)	600–1200
Planned outage rate (%)	16.7 (61 days/year)
Equivalent forced outage rate (%)	21.7
Average repair time (days)	5
Full capacity heat rate (kcal/kW·h)	2620
Half capacity heat rate (kcal/kW·h)	2760
Average incremental heat rate (kcal/kW·h)	2480
Annual average heat rate (kcal/kW·h)	2700
Minimum load (%)	50

$$\mathrm{SOR} = \frac{\mathrm{SOH}}{\mathrm{SH} + \mathrm{SOH}} = 0.192 \tag{G.1}$$

$$\frac{\mathrm{SH}}{\mathrm{PH}} = 0.704 \tag{G.2}$$

Combining Eqs (G.1) and (G.2) gives:

$$\frac{\mathrm{SOH}}{0.704 \times \mathrm{PH} + \mathrm{SOH}} = 0.192$$

which can be solved to find

$$\mathrm{SOH} = 0.167 \times \mathrm{PH}$$

and

$$\mathrm{POR} = \frac{\mathrm{SOH}}{\mathrm{PH}} = 0.167 = 16.7\% \text{ (61 days per year)}$$

Part of the scheduled outage hours of a nuclear plant is devoted to refuelling activities. Because these activities can vary from year to year, the numerical value given in Table G.I is representative of an average annual outage rate for LWRs.

TABLE G.II. TYPICAL TECHNICAL DATA FOR COAL-FIRED POWER PLANTS

Capacity (MW)	Steam	Flue gas desulph.	Equivalent forced outage rate[a] (%)	Average repair time (days)	Planned outage rate (days/year)	Net heat rates (kcal/kW·h)[b]			
						100%	25%[c]	Ave. incremental	Annual ave.
100	Sub[d]	No	6.2	2.6	29	2920	3740	2650	3000
200	Sub	No	9.2	3.0	39	2510	3230	2270	2590
200	Sub	Yes	11.7	3.0	39	2600	3300	2370	2670
400	Sub	No	13.5	3.6	48	2380	3060	2150	2460
400	Sub	Yes	16.0	3.6	48	2480	3170	2250	2560
400	Spr[e]	Yes	16.0	3.6	48	2370	3040	2150	2440
600	Sub	No	17.0	4.5	52	2380	3060	2150	2460
600	Sub	Yes	19.5	4.5	52	2480	3170	2250	2560
600	Spr	No	17.0	4.5	52	2280	2970	2050	2350
600	Spr	Yes	19.5	4.5	52	2380	3070	2150	2450
800	Spr	No	18.6	5.0	54	2280	2970	2050	2350
800	Spr	Yes	21.1	5.0	54	2380	3070	2150	2450
1000	Spr	No	21.7	5.0	55	2280	2970	2050	2350
1000	Spr	Yes	24.2	5.0	55	2380	3070	2150	2450

[a] The equivalent forced outage rates (EFORs) shown are based primarily on data for equivalent unplanned outage rates (EUORs) as defined in Section 6.3. However, comparisons of these parameters with less detailed estimates of EFORs [7] indicated that no adjustments were needed. The estimates shown here are reasonable for applications in planning and reliability modelling.

[b] These values are typical of bituminous coal-fired plants. Plants burning lignite coals would have net heat rates about 5% higher than these values (1 kcal = 4187 J).

[c] Minimum load.

[d] Subcritical steam.

[e] Supercritical steam.

Equivalent forced outage rates (EFORs), rather than equivalent unplanned outage rates (EUORs), are the correct parameters to use in most planning models such as WASP and in most production cost and reliability models. The EFOR shown in Table G.I is taken directly from Ref. [3], which actually represents an EUOR as defined in Section 6.3. However, since the economic shutdown hours (ESHs) are usually negligible for nuclear units, no adjustments were necessary in order to derive the appropriate EFOR.

As used in this appendix, the average incremental heat rate represents the average heat rate for an increment of power level between the minimum load (half capacity for a nuclear plant)[1] and the full load. The annual average heat rate is representative of the average heat rate obtained over the course of a typical year. It thus makes an allowance for the variations in power level that are typically seen in a base load plant. All heat rates in this appendix represent the net electrical capacity of the plant.

G.2. COAL-FIRED PLANTS

Coal-fired electric power plants range in size from about 100 MW to 1000 MW or more. Many of the newer plants fall into the 500–800 MW range because the economy of scale is not as great as it is for nuclear plants, and it can therefore be more easily balanced by the improved utility system reliability that comes from the use of smaller plants. Other variables in their design include steam conditions (subcritical or supercritical), coal type, and flue gas desulphurization (FGD). Although other design and operational factors can also affect the technical performance characteristics of power plants, these factors are generally the most significant. The following data are therefore limited to indicating the effects of these factors on coal-fired power plants.

Typical data for coal-fired plants are shown in Table G.II, and several observations can be made from them. First, the equivalent unscheduled outage rate, the average repair time, and the annual maintenance requirements all increase with plant capacity. This dependence is in contrast to that observed with nuclear plants. The inclusion of an FGD system in a coal-fired plant adds about 2.5% to the equivalent unscheduled outage rate. This increment does not truly reflect the forced outage rate of FGD systems, which average on the order of 20%; it represents an average value experienced in the USA. This reduced effect results largely from bypassing the flue gas round the FGD system during those times when the FGD system is on forced outage.

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[1] Although some reactor vendors state that their nuclear plants can be operated at power levels as low as 15% of full capacity, steady-state operation below about 50% of full capacity is only rarely reached in most nuclear plants.

TABLE G.III. TYPICAL TECHNICAL DATA FOR OIL-FIRED AND GAS-FIRED POWER PLANTS

Fuel/ capacity (MW)	Steam	Equivalent forced outage rate[a] (%)	Average repair time (days)	Planned outage rate (days/year)	Net heat rates (kcal/kW·h)[b]			
					100%	25%[c]	Ave. incremental	Annual ave.
Oil/100	Sub[d]	5.1	2.6	21	2900	3710	2630	2980
Oil/200	Sub	8.0	3.0	35	2470	3200	2230	2540
Oil/400	Sub	12.2	3.6	49	2370	3030	2150	2440
Oil/600	Sub	16.4	4.5	56	2370	3030	2150	2440
Oil/800	Spr[e]	18.4	5.0	61	2280	2920	2070	2340
Gas/100	Sub	3.6	2.6	12	2920	3740	2650	3010
Gas/200	Sub	5.5	3.0	28	2510	3220	2270	2590
Gas/400	Sub	8.4	3.6	47	2390	3060	2170	2460
Gas/600	Sub	12.9	4.5	57	2390	3060	2170	2460
Gas/800	Spr	14.7	5.0	64	2290	2940	2070	2360

[a] The equivalent forced outage rates (EFORs) have been estimated by adjusting the equivalent unplanned outage rates (EUORs) from Ref. [2] according to the EFOR values shown in Ref. [7], which are only tabulated for two broad categories of unit size.

[b] 1 kcal = 4187 J.

[c] Minimum load.

[d] Subcritical steam.

[e] Supercritical steam.

The net heat rate data in Table G.II are those associated with the burning of bituminous coal. Plants burning lignite coal would typically have net heat rates about 5% greater than the values reported here. This increase in net heat rate results from the increased electrical power used in handling the greater quantities of lower rank coal needed to produce the same net electrical power that can be produced with the higher rank, bituminous coal. The dependence of heat rate on steam conditions is also indicated by these data. Over the entire range considered, the heat rate for a supercritical design is about 4% less than for a subcritical design of the same net electrical capacity. The inclusion of an FGD system is seen to increase the plant heat rate by about 4%. This increase is due partially to the electrical requirements of the FGD system and partially to the need to reheat the flue gas before it is discharged to the atmosphere. With coal of lower sulphur content than the typical bituminous coal assumed here, the increase in heat rate would not be as large as that indicated here because some flue gas could be bypassed round the FGD system and used to reheat the gas that has been cleaned, thereby significantly reducing the energy requirements associated with the FGD system.

G.3. OIL- AND GAS-FIRED PLANTS

Although oil- and gas-fired plants are not generally viable options for new base load plants in the USA for legal and economic reasons, they continue to be used where they exist and often play an important role in countries with different economic and legal conditions. The appropriate O&M parameters for these plants are given in Table G.III. As before, these data represent experience in the USA. It was assumed that none of these plants is equipped with an FGD system.

Compared to the coal-fired plants of the same electrical capacity, the oil-fired plants have an advantage in unscheduled outage rate. For plants smaller than about 400 MW, the oil-fired plants also show an advantage in the annual scheduled maintenance requirements. A greater dependence of scheduled maintenance on size is indicated, however, so that, for plants of greater than about 400 MW capacity, the oil-fired plants require considerably more scheduled maintenance than the corresponding coal-fired plant.

The heat rates for these oil-fired plants are about 99% of those for coal-fired plants of comparable design. These data indicate that the minimum heat rate for subcritical steam conditions is reached at plant size of 400 MW or greater. The use of supercritical steam in the 800 MW concept improves the heat rate by about 4%.

Unscheduled outage rates for natural gas-fired power plants are somewhat lower than the corresponding oil-fired plants. Compared to oil-fired plants, the smaller (less than 400 MW) gas-fired plants are shown to have considerably shorter scheduled maintenance requirements. For the larger sizes this advantage shifts to the oil-fired plants.

TABLE G.IV. TYPICAL TECHNICAL DATA FOR OTHER POWER PLANTS

Type	Capacity (MW)	Equivalent forced outage rate (%)	Average repair time (days)	Planned outage rate (days/year)	Net heat rates (kcal/kW·h)[a]			
					100%	50%	Ave. incremental	Annual ave.
Combustion turbine (conventional)	25–250	8.0–44.8[b]	2	12	2950	3630	2270	3530
Combustion turbine (advanced)	100–250	8.0–44.8[b]	2	12	2650	3250	2050	3180
Hydroelectric	All	1.8[c]	1	13	–	–	–	–
Pumped storage	All	16.6[c]	2	33	(d)	(d)	(d)	(d)
Oil-fired	250	10.0[e]	2	26	2120	2340	1900	2190

[a] 1 kcal = 4187 J.

[b] See text for explanation of EFOR ranges.

[c] The equivalent forced outage rate (EFOR) for hydroelectric and pumped storage is taken directly from Ref. [7].

[d] Although a pumped storage facility does not have a heat rate value, some electrical energy was used to pump the water to the storage location. While the amount of electrical energy for this effort is dependent on site-specific parameters such as distance between reservoirs and the local topography, an overall cycle efficiency of 67% is a reasonable average. Thus, for every two units of usable electrical energy obtained from the pumped storage facility, three units were consumed.

[e] The EFOR for oil-fired combined cycle units was increased by 10% (from Ref. [2] data according to the explanation given with Table G.III).

Heat rates for gas-fired plants are slightly greater than the corresponding oil-fired plant and are, in fact, very nearly equal to the corresponding coal-fired plant. Supercritical steam conditions in the larger plants again provide a 4% improvement in heat rate.

G.4. OTHER POWER PLANTS

Other types of power plant typically used in electric utility systems include combustion turbines, hydroelectric plants, pumped storage plants, and combined cycle systems. Typical operating parameters for these technologies are given in Table G.IV. Data are presented for two types of combustion turbines – a conventional design typically used in older units and an advanced design that has recently become commercially available. The advanced design has a combustor exhaust temperature of about 1200°C as compared to 1100°C in the older units. This increased temperature yields an increase in thermal efficiency of about 10%.

Equivalent forced outage rates (EFORs) for combustion turbines are highly dependent on their usage levels. In applications where they are called on regularly for sustained periods, combustion turbines have exhibited low failure rates. However, in situations where they are used infrequently and for short periods, combustion turbines have shown extremely high forced outage rates.

A range of EFORs is given in Table G.IV to reflect this sensitivity to the type of use that may occur. The upper end of the range (44.8% EFOR) is taken directly from Ref. [7] and corresponds to the operating histories for nearly 650 units with an overall average capacity factor of 8.4%. The lower end of the forced outage range (8.0%) is taken from Ref. [2], which actually represents an equivalent unplanned outage rate (EUOR). An assumption is made in this case that the EFOR approaches the EUOR for these types of unit as their usage levels increase (i.e. as the reserve shutdown hours decrease). Special attention should be given to the selection of EFOR values for these units in order to account for case-specific variations.

REFERENCES

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[2] ELECTRIC POWER RESEARCH INSTITUTE, Technical Assessment Guide, Rep. EPRI P-1950-SR, Palo Alto, CA (1981).

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[4] ELLISON, W., LEFTON, S.A., FGDS reliability: what's being done to achieve it, Power (May 1982).
[5] DERDIGER, J.A., BHATT, K.M., SIEGFRIED, W.E., Component Failure and Repair Data for Coal-Fired Power Units, Electric Power Research Inst. Rep. EPRI AP-2071 (1981).
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Appendix H

ILLUSTRATIVE ECONOMIC DATA FOR THERMAL ELECTRIC POWER PLANTS

The information required for an electric system expansion plan includes capital and operating costs for various types of generating plants that are to be considered. These costs should, as far as possible, be based on a consistent, systematic methodology and adjusted to the specific conditions applicable to the study being undertaken.

This appendix describes the major components and parameters that comprise the total capital investment cost of a power plant and the non-fuel operating and maintenance costs. The specific numerical examples are based on recent experience in the USA[1]. The corresponding costs in other countries may be higher or lower depending on specific local conditions such as availability and cost of local labour, domestic manufacturing capabilities, foreign exchange rate, local safety and environmental requirements. Factors such as these have resulted in a wide range of costs even within the USA. A detailed breakdown of the cost is provided so that, where appropriate, adjustments to the information in this appendix can be made.

Anyone conducting an expansion planning study should obtain detailed cost information relative to their specific conditions rather than use the numerical values presented in this appendix. These data are, however, illustrative of the type of information needed and represent reasonable values for the purposes of this guidebook. The methodology used to obtain these values is discussed and can also be useful when used with site-specific cost information developed for any actual case study.

H.1. CAPITAL INVESTMENT COSTS

H.1.1. General

The total capital investment cost for an electric power plant includes the direct costs, indirect costs, owner's costs and spare parts costs (sometimes taken collectively and called preproduction and inventory costs), contingencies, escalation, and an allowance for funds used during construction. Each of these components is discussed in detail below for both nuclear and coal-fired power plants. For other fossil-fired plants only the total capital costs are given.

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[1] All costs are expressed in beginning-of-year 1982 US dollars unless otherwise stated.

Direct costs

The direct capital cost of a power plant includes those costs associated with the purchase and installation of plant components. It consists of the factory equipment costs and the site installation costs. The latter include the site labour costs (which in turn include both wages and benefits for the labour force) and the costs of installation materials (e.g. welding material, reinforcement rods, wiring).

In estimating direct capital costs it is often useful to divide the plant into several subsystems and make separate estimates for each. This method has the advantage that the contribution of each subsystem to the total cost is easily seen and the effects of changes in the subsystem can be more readily estimated. For example, the cost of flue gas desulphurization (FGD) systems in coal-fired plants, which would otherwise be buried in the total plant cost, can be identified by this technique. Furthermore, the effect of design changes, e.g. in the turbogenerator set, can be more readily quantified.

The structure shown in Table H.I is one way of dividing the plant into several subsystems. It is based on a structure used in IAEA evaluations for several years with a slight modification: for the purposes of this appendix, the cost of the FGD system is separated from the reactor/boiler subsystem in which it would normally be found. Because different countries may have different approaches to and requirements for sulphur removal, a separate FGD subsystem has been added to the items listed in Table H.I. The capital cost estimates are divided into factory equipment and installation costs. Man-hour estimates for site installation are also provided.

Indirect costs

The indirect costs include construction services (e.g. temporary site facilities, tools, fuels, lubricants, permits) project management, and home and field office engineering services. These costs are often expressed as a percentage of the total direct capital costs.

Owner's costs and spare parts

These are intended to cover items such as administrative costs, operator training, equipment checkout, initial startup problems, and an inventory of fuels and consumables sufficient for at least one month of full power operation. (Spares must also be available to cope with equipment malfunctions and/or breakdowns.) Estimates of supplementary costs are both site- and user-specific.

Contingencies

Two types of contingency are associated with a modern electric power plant. The first is *project contingency* and represents an allowance for additional

TABLE H.I. STRUCTURE OF THE POWER PLANT CAPITAL INVESTMENT COST

Direct costs		Land and land rights
		Structures and site facilities
		Reactor or boiler equipment
		Flue gas desulphurization (if appropriate)
		Turbine plant equipment
		Electric plant equipment
		Miscellaneous plant equipment
		Water intake and heat rejection system
Indirect costs		Ancillary construction facilities
		Construction management, equipment and services
		Home office engineering and services
		Field office engineering and services
Base cost = Direct cost + Indirect cost		
Fore cost = Base cost + Supplementary cost		Owner's cost
		Spare parts
		Contingency
Total capital investment cost	= Fore cost + Financial cost	Escalation (EDP)[a]
		Allowance for funds used during construction (AFUDC)
		Interest on escalation[a]

[a] These items are zero if the total capital investment cost is expressed in constant money of the date of start of construction.

costs that could arise from a more detailed design of a definitive project. In the USA, a value equal to 15% of the sum of the direct and indirect costs is commonly used for the project contingency in fossil-fuelled power plants. A 20% project contingency is typically used for nuclear plants because of the greater uncertainty in their estimated costs.

The second type is *process contingency* and is used to account for the potential cost increases resulting from the design and construction of relatively new or unproved technologies used within the power plant. The process contingency decreases as experience with a new technology is gained.

Escalation and allowance for funds used during construction (AFUDC)

Escalation during construction represents the cost increases that occur in the time between the original estimates and when the component is actually purchased. It can be estimated in a similar way to that discussed for general escalation in Chapters 5 and 6. In some capital cost estimates, the costs are expressed in terms of constant monetary units (e.g. dollars) at the date of the start of construction so that escalation during construction is not included in the estimates.

The allowance for funds used during construction accounts for the interest payments accrued during the construction period. A simplified hypothetical example is given later so that the user will be familiar with the basic methodology used to estimate AFUDC.

Owing to the widely varying escalation rates, construction periods and financing alternatives that exist throughout the world and over time, estimates for escalation and allowance for funds (i.e. interest) used during construction are not given here. These costs are sometimes referred to as the financial costs of the project.

Decommissioning

Associated with capital investment costs is a final cost component which relates to the decommissioning of a plant. This cost will occur after the end of the useful life of the facility and can involve any of several different strategies. For a nuclear power plant there are at present three ways to effect decommissioning:

(a) *Mothballing,* which means putting the facility into a state of protective storage. In general, all fuel assemblies and radioactive fluids and wastes are removed from the site but the facility itself is left intact. Adequate radiation monitoring, environmental surveillance, and appropriate security procedures are established under a possession-only licence to ensure the health and safety of the public.

(b) *Entombment,* which means sealing all the highly radioactive and contaminated components (e.g. the reactor pressure vessel and internals) within a structure integral to the primary biological shield. All fuel assemblies, radioactive fluids and wastes, and certain selected components are shipped off-site. The structure should provide integrity during the period of time when significant quantities of radioactivity remain with the material in the entombment. As in mothballing, an appropriate and continuing surveillance programme is established under a possession-only licence.

(c) *Immediate dismantling.* All fuel assemblies, radioactive fluids and wastes, and any other materials with activities above accepted unrestricted levels are removed from the site, which may then be released for unrestricted use.

A fourth option is available to the utility or plant owner. This is to recommission or convert the plant by replacing the steam supply system by a new one, in which case the costs can be charged to the new plant.

For a coal-fired or oil-fired plant, the usual strategy is total dismantling at end of plant life (in view of the salvage value of scrap metal and other equipment) and the use of the site for similar or other purposes.

Decommissioning costs, even though they may be substantial, contribute very little to total generation costs. This is because they involve amounts of money to be spent many years after plant startup. When these costs are 'present-worthed', i.e. converted to prices at year of plant commercial operation, their effects are minimal. There is significant salvage value for the PHWR plant type, since the heavy water available can be reconditioned and used again.

H.1.2. Nuclear plants

There are several types of nuclear power plants in the world market, including light water reactors (LWRs), heavy water reactors (HWRs), gas cooled reactors (GCRs), and light water gas cooled reactors (LWGRs). Each type offers advantages that may be significant in any given application. About 85% of the nuclear generated electric capacity currently in operation or under construction is of the LWR type, and therefore data for LWRs are given in this appendix. Although there are slight differences in the costs of pressurized water reactors (PWR) and boiling water reactors (BWR) (the two types of light water reactors), these data are applicable to both types.

Typical base load LWR nuclear power plants have net electrical outputs in the range 600–1300 MW. Almost all the most recent plants built in the USA are over 1000 MW. This is due to the high capital costs of nuclear plants and the economy of scale in these costs. (Recent experience indicates, however, that the economy of scale advantage may be eroding.) The detailed cost data presented below illustrate a 1200 MW LWR in conditions prevailing in the USA. Estimates of the total capital cost of 600 MW and 900 MW plants are also presented and briefly discussed.

Land and land rights

A single 1200 MW nuclear power plant would typically require on the order of $3.2 \times 10^6\,m^2$ of land, including the building site and an exclusion area surrounding it. Since legal requirements for the exclusion area may vary in different countries, this land requirement should be taken as an approximate figure only.

TABLE H.II. SUMMARY OF DIRECT CAPITAL COSTS FOR A 1200 MW LWR *(in 1982 US $)*

Subsystem	Factory equipment (10^6 $)	Installation (10^6 $)	Total (10^6 $)	Total ($/kW)	Site labour (10^3 man-hours)
Land	–	3	3	3	–
Structures and site facilities	9	213	222	185	8 600
Reactor	186	73	259	216	3 120
Turbine plant	157	58	215	179	2 730
Electric plant	29	51	80	66	2 220
Miscellaneous	12	12	24	20	520
Water intake and heat rejection	25	11	36	30	510
Total direct cost (rounded)	420	420	840	700	17 770

Land costs can vary significantly depending on local conditions. A value of US $ 1/m^2 is assumed in the example given in Table H.II. Land costs represent a very small portion of the total capital requirement for a nuclear power plant, and therefore large uncertainties in the land requirement or cost will have no significant effect on the total cost estimate.

Structures and site facilities

This subsystem includes all buildings, structures and improvements associated with the plant. The major components of this cost are those of site labour and site materials (e.g. concrete, reinforcing steel). Only about 4% of this expenditure is for factory equipment; the site labour and installation costs contribute the remainder.

Reactor equipment subsystem

This includes the nuclear steam supply system, fuel handling and storage equipment, radwaste processing equipment, instrumentation and control mechanisms, and other equipment directly associated with the steam supply system. About 72% of this expenditure is for factory equipment (principally the steam supply system), and 28% is for site labour and installation.

Turbine plant equipment subsystem

This includes the turbine-generator set and all associated ancillary equipment such as condensing equipment, feedwater heating system, and chemical treatment facilities. About 73% of this expenditure is for factory equipment.

Electric plant equipment subsystem

This includes the switchgear equipment, transformers and protective systems associated with the electrical portion of the plant. Its principal functions are to deliver the electric power generated in the plant to the step-up transformers, to control and meter the electric energy, and to protect these components. It includes the power source for the plant auxiliaries as well as plant control, protection and surveillance systems. Approximately 36% of this expenditure is for factory equipment.

Miscellaneous plant equipment subsystem

This includes the miscellaneous equipment needed for operation and maintenance of the plant. General purpose cranes, hoists, compressed air units, communications equipment, etc., are included in this subsystem. About 50% of this expenditure is for factory equipment.

Water intake and heat rejection subsystem

In the USA, cooling towers are often used as the main heat rejection system. Although several types of towers are available, the cost estimates in Table H.II are based on mechanical draft wet cooling towers. The subsystem also includes circulating water pumps, filters and pumps used to supply make-up water from a river or lake, and water treatment facilities. About 70% of this expenditure is for factory equipment.

This estimate assumes that mechanical draft wet cooling towers are used. The use of other heat rejection techniques, such as once-through cooling or cooling ponds, could significantly change the cost of this subsystem.

Total direct costs

The direct costs of the individual subsystems for a 1200 MW LWR are summarized in Table H.II, which shows that the total direct cost for such a plant is about $ 840 million. Approximately one half of this expenditure is for factory equipment and the other half is for site labour and installation materials. The total site labour requirement is equal to almost 15 man-hours/kW.

TABLE H.III. FORE COSTS FOR A 1200 MW LWR POWER PLANT
(in 1982 US $)

	(10^6 $)	($/kW)
Direct costs (rounded)	840	700
Indirect costs	436	364
Owner's costs and spare parts	42	35
Contingencies	255	212
Fore cost (rounded)	1570	1310

Indirect costs

The indirect capital costs of a power plant include the costs of construction services and home and field office engineering services. For nuclear plants built in the USA, these indirect costs are typically equal to about 52% of the direct capital cost, as shown in Table H.III.

Owner's costs and spare parts

These costs are intended to cover the initial operating expenses that the owner of the plant will incur, such as operator training, equipment and instrument checkouts, initial startup problems. For nuclear plants, estimates of these costs are dependent on utility practices and experience with nuclear power. In particular, those utilities that already have operating reactors would probably incur smaller costs of this type than a utility building its first nuclear power plant. Although this cost category is quite variable, a value equal to 5% of the total direct capital cost represents a reasonable average. (These expenditures are sometimes included in the indirect costs discussed above. In those cases, the 52% used to estimate the *indirect costs* should be increased to 57%.)

Contingencies

The project contingency of a power plant represents an allowance for additional costs that could arise from a more detailed design for a specific project. For nuclear plants, a project contingency equal to 20% of the sum of the direct and indirect costs is typically applied. This value is somewhat greater than the 15% applied to fossil-fuelled plants because of the greater uncertainty with respect to the final design of safety-related items on the nuclear plant.

TABLE H.IV. EFFECT OF PLANT CAPACITY ON LWR FORE COSTS
(in 1982 US $)

Plant capacity (MW)	Fore costs	
	(10^6 $)	($/kW)
1200	1570	1310
900	1350	1500
600	1090	1810

The LWR technology is sufficiently advanced for an additional process contingency not to be generally needed in estimating capital costs for plants using this technology.

Fore cost

The costs discussed above are summarized in Table H.III. As indicated in Table H.I, the sum of these costs is referred to as the fore cost of an electric power plant. For the 1200 MW LWR considered here, the fore cost is estimated to be about $1570 million, or $1310/kW.

Cost-size relationship for nuclear power plants

Most LWR nuclear power plants built recently in industrialized countries have a net electrical capacity greater than 1000 MW. In other countries, plants of lower capacity may be more appropriate for reasons concerned with both economics and utility system size. Estimates of the fore costs for 900 MW and 600 MW LWR power plants are therefore given in Table H.IV. Since most of the available cost data are for the larger plants, it must be recognized that the uncertainty in these estimates increases with decreasing plant size. Although there may be a market now or in the future for even smaller nuclear power plants, the cost estimates are considered very uncertain and are therefore not discussed here.

Decommissioning

Table H.V gives a range of decommissioning costs for the three options discussed; Table H.VI shows a range of annual costs associated with decommissioning estimated for industrialized countries.

TABLE H.V. RANGES OF DECOMMISSIONING COSTS*
(in 10^6 December 1982 US $)

	PWR			BWR		
	High	Average	Low	High	Average	Low
Mothballing	15	7	4	25	10	5
Entombment	50	20	8	50	30	15
Dismantling	130	70	30	155	85	40

* Excluding maintenance, surveillance, security and contingency costs.

TABLE H.VI. RANGE OF ANNUAL COSTS ASSOCIATED WITH DECOMMISSIONING: INDUSTRIALIZED COUNTRIES
(in December 1982 US $ per year)

	High	Low
Security guard force	205 000	115 000
Monitoring programme	40 000	25 000
Annual care and surveillance:		
Mothballing	160 000	90 000
Entombment	150 000	70 000

H.1.3. Coal-fired plants

Coal-fired electric power plants are being designed and constructed for net electrical outputs ranging from 100 MW to more than 1000 MW. The majority of the base load plants are, however, in the 300–900 MW range, and although the emphasis in this section is on plants of this size, some information on larger and smaller plants is also presented.

The type of coal burned can affect both the capital and operating costs of a plant. With one exception, the magnitude of these effects is usually small enough to be neglected when estimating costs for planning purposes. One coal characteristic that can significantly affect costs is sulphur content. When SO_2 must be removed from the flue gas before its release to the atmosphere, both the capital and operating costs of the plant will be increased. As discussed in Appendix G, the SO_2 removal system will also affect the performance of the plant. Since its effect on plant costs can be significant, flue gas desulphurization (FGD) will be considered separately. Detailed estimates will be given for the capital costs for a 600 MW coal-fired plant, both with and without an FGD system.

Land and land rights

A 600 MW coal-fired plant would typically require about $1.6 \times 10^6 m^2$ for the site. If the coal has a high sulphur content to be removed from the flue gas with a wet scrubber system, a waste disposal area of approximately $1.2 \times 10^6 m^2$ must also be provided. Even if SO_2 is not removed from the flue gas, a small waste disposal site must be provided for the ash produced when the coal is burned. (For this example, the $1.2 \times 10^6 m^2$ waste disposal requirement is assumed.)

Land costs can vary significantly depending on local conditions. A value of $\$1/m^2$ is assumed in the example given in Table H.VII. It will be seen that land costs represent only a small portion of the total capital requirement for a power plant, so the uncertainty in land requirement or cost will not have a large effect on the total cost estimate.

Structures and site facilities

This subsystem includes all buildings, structures and improvements associated with the plant. The major components of the cost are site labour and site materials (e.g. concrete, reinforcing steel). Based on experience in the USA, only 4% of this expenditure is due to factory equipment, the rest being associated with site labour and installation costs.

Boiler equipment

This subsystem includes the coal handling equipment (assumed to include railway car dumping equipment, crushers, conveyors, etc.), the boiler, the flue gas draft components, the waste handling equipment (not including the waste from the FGD subsystem), and electrostatic precipitators (ESPs) for removing fly ash from the flue gas.

There is a wide range of estimates for the cost of electrostatic precipitators. A reasonable average is about 11% of the direct capital cost for the boiler equipment for a 600 MW plant.

Typical cost breakdowns show that about 73% of the expenditure is for factory equipment and 27% for site labour and installation.

Flue gas desulphurization (FGD)

The FGD subsystem encompasses all those components needed to remove SO_2 from the flue gas. As such, it includes the sorbent (usually lime or limestone)

TABLE H.VII. SUMMARY OF DIRECT CAPITAL COSTS FOR A 600 MW COAL-FIRED PLANT
(in 1982 US $)

Subsystem	Factory equipment (10^6 $)	Installation (10^6 $)	Total (10^6 $)	Total ($/kW)	Labour (10^3 man-hours)
Land	–	3	3	5	–
Structure and site facilities	2	58	60	100	1 200
Boiler	149	55	204	341	1 700
Flue gas desulphurization (FGD)	50	27	77	129	680
Turbine plant	60	17	77	128	820
Electric plant	13	23	36	60	760
Miscellaneous	5	3	8	14	140
Heat rejection	12	4	16	26	170
Total direct cost (rounded):					
(without FGD)	240	160	400	670	4 790
(with FGD)	290	190	480	800	5 470

handling and preparation facilities, the scrubber modules (consisting principally of a spray tower and mist eliminator), a heating system for reheating the cleaned gas prior to discharge, a sludge disposal system, and all the ductwork, pumps, fans, etc., that would not be needed if an FGD system were not used. Although several processes are possible, it is assumed that the wet lime or limestone process will be used. These processes make up the majority of the FGD systems operating or under construction in the USA. For this appendix it is assumed that the FGD system must be designed to remove 90% of the SO_2 produced by burning bituminous coal with a sulphur content of 4%.

Current practice in the USA is to install modular FGD systems and include a spare, or redundant, module so that plant reliability is improved. For example, a 600 MW plant burning high-sulphur coal might have five scrubber modules each rated at 25% of plant capacity. This FGD system would have direct capital cost of approximately $ 77 million. About 65% of this expenditure is for factory equipment and 35% for labour and installation. For low-sulphur coal (i.e. with a sulphur content less than 1%), where only 70% of the SO_2 must be removed, the estimated capital cost for this subsystem is about 75% of the value for the same plant burning high-sulphur coal.

Turbine plant equipment

This subsystem includes the turbine generator set and all associated ancillary equipment such as condensing equipment, feedwater heating system, chemical treatment facilities. An estimate for a 600 MW plant would be approximately \$77 million, about 78% of which is for factory equipment and 22% for labour and installation.

Electric plant equipment

This subsystem includes the switchgear equipment, transformers, electrical cables, and protective systems associated with the electrical portion of the plant. Its principal functions are to convey the electrical power generated in the plant to the step-up transformers, to control and meter the electric energy, and to protect these components. It also includes the power source for plant auxiliaries and plant control, protection and surveillance systems during both normal and emergency situations.

The electric plant equipment for a 600 MW plant would cost approximately \$36 million, about 35% of which is for factory equipment and 65% for labour and installation.

Miscellaneous plant equipment

This subsystem contains the miscellaneous equipment needed for operation and maintenance of the plant. Cranes, hoists, general purpose compressed air units, etc., are included in it. The direct capital cost for a 600 MW plant would be about \$8 million, about 63% of which is for factory equipment.

Water intake and heat rejection system

In the USA, cooling towers are often used as the main heat rejection system. Although several types are available, the cost estimates given below are based on mechanical draught wet cooling towers. The system also includes the circulating water pumps, filters and pumps used to supply make-up water from a river or lake, and water treatment facilities. The estimated cost for a 600 MW coal-fired plant is \$16 million, about 75% of which is for factory equipment and 25% for labour and installation.

Total direct cost

The direct costs of the individual subsystems for a 600 MW coal-fired plant are summarized in Table H.VII. The total direct cost is the sum of the costs discussed above. A 600 MW plant without an FGD system (but with an ESP) has an estimated total direct cost of about \$400 million, about 60% of which is for factory equipment and 40% for labour and installation materials. The inclusion of a wet lime or limestone FGD system would increase the direct cost of the 600 MW plant to about \$480 million.

Indirect costs

The indirect costs include the costs of construction services (e.g. temporary facilities, permits) and home and field office engineering services. These costs are often expressed as a percentage of the direct capital costs, 18% being a representative value.

Owner's costs and spare parts

These costs are intended to cover the initial operating expenses that the owner of the plant will incur, such as operator training, equipment checkout, initial startup problems, and an inventory of fuels and consumables sufficient for one month of full power operation. Although estimates of these costs are both site- and user-specific, a value equal to 5% of the total direct cost represents a good approximation. (These costs are sometimes included in the indirect capital costs discussed above, in which cases the 18% used to estimate the *indirect costs* should be increased to 23%.)

Contingencies

In the USA a value equal to 15% of the sum of the direct and indirect costs is commonly used for the *project contingency* of fossil-fuelled plants (see Section H.1.1, Contingencies, for details).

Conventional coal-burning plants are based on well-established technologies and processes that have evolved over many years of plant construction and operation. As a result, only the most recent changes in the basic concepts require a *process contingency* (see Section H.1.1). FGD systems are comparatively new processes, and a small process contingency (5%) is commonly added to the FGD portion of the total plant cost. No other parts of a conventional coal-burning plant represent new processes and thus no additional process contingencies are generally applied.

TABLE H.VIII. FORE COSTS FOR A 600 MW COAL-FIRED PLANT
(in 1982 US $)

	Without FGD		With FGD	
	(10^6 $)	($/kW)	(10^6 $)	($/kW)
Direct costs	404	674	481	803
Indirect costs	73	122	87	145
Owner's costs and spare parts	20	34	24	40
Contingencies	72	119	90	149
Fore cost (rounded)	570	950.	680	1140

TABLE H.IX. FORE COSTS FOR VARIOUS COAL-FIRED PLANTS
(in 1982 US $/kW)

Type of plant	Plant capacity (MW)				
	200	300	600	900	1200
Without FGD	1420	1220	950	830	790
With FGD	1680	1450	1140	1000	950

Fore cost

The costs discussed above are summarized in Table H.VIII. The sum of these costs is referred to as the fore cost of an electric power plant. For a 600 MW plant without FGD the fore cost is estimated to be about $ 570 million or $ 950/kW, and for the same capacity plant with FGD the fore cost is about $ 680 million or $ 1140/kW.

Summary of capital costs for coal-fired plants

Estimated fore costs for coal-fired electric power plants of several unit sizes are presented in Table H.IX. These estimates indicate that an overall scaling factor of 0.35 is appropriate in the 200–900 MW range. This factor is applied to the

TABLE H.X. FORE COSTS FOR OTHER FOSSIL-FUELLED POWER PLANTS
(in 1982 US $/kW)

Type of plant	Plant capacity (MW)				
	100	200	300	600	900
Residual oil	1440	1120	970	760	660
Combustion turbine – residual oil	320	–	–	–	–
Combined cycle – residual oil	–	740	640	510	–

specific cost ($/kW) of these plants. For plants larger than about 900 MW, the scale factor is reduced to about 0.18 owing to turbogenerator design changes needed to accommodate this greater capacity. The data in Table H.IX indicate that a wet lime or limestone FGD system adds about 19% to the capital cost of a coal-fired plant. The costs in this table include estimates for an ESP, the cost of which represents about 5% of the total plant cost. Thus the combined cost of an ESP and FGD typically adds nearly 25% to the cost of the same plant without these environmental controls.

H.1.4. Other fossil-fired plants

Electric power plants can also be designed to burn other types of fossil fuels. Estimates of the fore costs of these plants are given in Table H.X for a range of typical plant capacities. The capital costs for these plants can change significantly according to local conditions. These values represent typical values based on experience in the USA.

The oil-fired combined cycle plants in Table H.X represent plants designed to make more efficient use of expensive oil fuels, i.e. to lower the net heat rate. In such plants the exhaust gas from the combustion turbogenerator is passed through a heat recovery boiler where it produces steam, which is routed to a steam turbine where it is expanded to produce additional electricity. As seen in Table G.IV, this design concept results in a plant heat rate that can be significantly lower than conventional oil-fired plants[2].

The capital costs for plants burning distillate oil would be approximately 90% of those shown in Table H.X for residual oil.

[2] See ELECTRIC POWER RESEARCH INSTITUTE, Technical Assessment Guide, Rep. EPRI P-2410-SR (1982) for a brief description.

H.1.5. Interest during construction

Associated with every project are the financial costs of the use of capital. Money borrowed or committed for project implementation must eventually be paid back or recovered, with interest. A generic term in wide use is *allowance for funds used during construction (AFUDC)*, which includes the interest during construction (IDC) as well as certain brokerage fees and other expenses related to the procurement of the loans. As money is borrowed or committed to a project, interest charges begin to accumulate in direct proportion to the outstanding balance. The amount of interest can be calculated from a knowledge of the cash flow for the particualr project.

Two generalized methods for calculating interest during construction are discussed in the following paragraphs, and a simple hypothetical example is given for each technique. By following either example, the user will be able to estimate the IDC for a particular project.

In the first method it is assumed that a quantity of money is borrowed at the beginning of a given year. To determine the interest charges on this money, the amount borrowed is multiplied by the factor $(1+i)^n$, where i is the effective annual interest rate and n is the number of years between the time the money is borrowed and the time of commercial operation (i.e. the time when the owner can begin to pay money back). In the next year, a different amount of money is borrowed (possibly at a different interest rate i′). This amount is multiplied by the factor $(1+i')^{n-1}$, where the term n−1 reflects that this money was borrowed for one less year than the previous amount. This procedure is repeated for all subsequent years up to the commercial operation of the plant. The amounts are then added up, and the capital initially borrowed or committed for each year is summed and then subtracted from the earlier total. The result is the interest during construction.

A simple example using this method is given below. This illustrates the process usually followed when making capital cost estimates for electric power plants. The capital expenditure that must be borrowed or committed for a project is represented by its fore cost. For this example, assume that the fore cost is equal to \$ 1500/kW. Further assume that this money is spent in the following manner:

Year 1	10%
Year 2	20%
Year 3	30%
Year 4	20%
Year 5	15%
Year 6	5%
Total	100% of fore cost

Commercial operation begins at the end of Year 6 in this example. The expenditure of money as described here is often referred to as an 'S curve' of capital spending.

For simplicity, a constant charge rate of 10% per year is used in this example. The estimated interest during construction (IDC) is determined by the following relationship:

$$\begin{aligned} \text{IDC} &= (\$1500/\text{kW})\,[((1.1)^6 - 1)(0.1) + ((1.1)^5 - 1)(0.2) \\ &\quad + ((1.1)^4 - 1)(0.3) + ((1.1)^3 - 1)(0.2) + ((1.1)^2 - 1)(0.15) \\ &\quad + ((1.1) - 1)(0.05)] \\ &= (\$1500/\text{kW})(0.4412) = \$662/\text{kW or } 44.1\% \text{ of fore cost} \end{aligned}$$

In some cases the detailed cash flow, i.e. the S curve, may not be known. A second method can then be used to estimate the IDC. In this case it is given by the relationship:

$$\text{IDC} = (\text{fore cost})\,[(1+i)^{n/2} - 1]$$

The basic assumption here is that all the capital costs occur at a point in time halfway through the construction lead time, i.e. halfway between the initial pour of concrete and commercial operation. Using the previous example, the estimated IDC becomes:

$$\begin{aligned} \text{IDC} &= (\$1500/\text{kW})\,[(1.1)^3 - 1] \\ &= (\$1500/\text{kW})(0.331) \\ &= \$496/\text{kW or } 33.1\% \text{ of fore cost} \end{aligned}$$

When a reasonable estimate of the S curve is available, it is recommended that it be used, because it is more accurate. With either method, however, IDC can be seen to be a significant fraction of the total cost of the project. Appendix D gives typical cash flow curves and tables to calculate the IDC.

H.2. CONSTRUCTION PERIODS

The construction period for any electric power plant depends on several factors, including labour productivity, weather, regulatory actions and site characteristics. The construction duration periods for electric power plants are given below, based on experiences in the USA. This period represents the time between the first pour of concrete and, for nuclear plants, fuel loading. For fossil-fired plants, first steam production marks the end of the construction period:

Nuclear	7 to 9 years
Coal-fired	4 years for plants of the order of 500 MW and 5 years for plants of about 1000 MW
Oil-fired	4 years for 500 MW plants
Combustion turbines	1 year
Combined cycle	2 years

TABLE H.XI. FIXED O&M COSTS FOR POWER PLANTS
(in 1982 US $/kW·a)

Type of plant	Plant capacity (MW)					
	100	200	300	600	900	1200
Nuclear	–	–	–	18–32	18–32	18–32
Coal without FGD	–	11	10	8	7	7
Coal with FGD	–	22	20	16	14	13
Residual oil fired	4	3	3	2	2	2
Combustion turbine – residual oil	0.4	–	–	–	–	–
Combined cycle – residual oil	–	7	6	5	4	–

These estimates include only the actual construction of the plant. Design time and time for other preconstruction activities must be completed before the start of construction, and various operation startup activities must be completed before commercial operation begins.

Although the above times are reasonable estimates for what is needed for plant construction, the actual time for any given case can be much greater. This is especially true of nuclear plants, where design changes and delays in obtaining licences and permits have resulted in construction times of the order of 10–13 years[3].

H.3. OPERATION AND MAINTENANCE (O&M) COSTS

O&M costs can be considered to be made up of two components: fixed costs (those that are invariant with the electrical output of the plant) and variable costs (non-fuel costs incurred as a consequence of plant operation, waste disposal costs or the cost of limestone in an FGD system). Typical estimates of these costs are presented below for different types of power plants.

[3] For additional details on power plant lead times, see BAUMAN, D.S., MORRIS, P.A., RICE, T.R., An Analysis of Power Plant Construction Lead Times: Vol. 1 – Analysis and Results, Electric Power Research Inst. Rep. EPRI EA-2880 (1983).

TABLE H.XII. VARIABLE O&M COSTS FOR POWER PLANTS
(in 1982 US $)

Type of plant	Variable O&M (mills/kW·h)
Nuclear	2
Coal without FGD	1
Coal with FGD	4
Residual oil fired	2
Combustion turbine – residual oil	3
Combined cycle – residual oil	2

H.3.1. Fixed O&M costs

Annual fixed O&M costs (expressed in US $/kW·a) are dependent on fuel type, plant capacity and, for coal-fired plants, the presence of an FGD system. Table H.XI summarizes typical fixed O&M costs based on experience in the USA. These data are based on the assumption that a single generating unit exists at each site. In actual practice these costs could vary on a site-by-site basis owing to local conditions and the operating philosophy of the plant owner/operator.

H.3.2. Variable O&M costs

Variable O&M costs are those charges that result from actual operation of the plant. Although some estimators add a third O&M category, 'consumables', to cover the cost of non-fuel materials consumed during plant operation (e.g. water or FGD sorbent), these costs are not separated from the variable O&M costs in the data presented in Table H.XII. None of the types of plant in this table shows a dependence of variable O&M costs on plant size. Factors that can, however, influence these costs include coal type (both with respect to sulphur removal and solid waste disposal), maintenance practices and plant design (e.g. supercritical steam versus subcritical steam). The estimates in Table H.XII are based on power plant experience in the USA. The value given for coal with FGD is based on the use of high-sulphur coal. A corresponding value for low-sulphur coal would be 1–2 mills/kW·h lower.

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Appendix I

PARAMETRIC COSTS OF CONVENTIONAL HYDROELECTRIC AND PUMPED STORAGE HYDROELECTRIC PLANTS*

I.1. CONVENTIONAL HYDROELECTRIC PARAMETRIC COSTS

I.1.1. Introduction

A conventional hydroelectric power plant is one in which water moves in one direction only, to produce power by the action of gravity as it causes water to move through a turbine. Any hydroelectric plant is composed of a number of components each of which varies in cost in accordance with its own parameters. As an illustration, a dam 40 m high and 450 m long might be part of a plant developing 100 MW under 40 m head or of a plant developing 500 MW under 350 m head. The first plant would have short water conduits and would develop the head of the dam only; the second would develop additional head with the aid of longer water conductors between the dam and powerhouse. Such water conductors might be tunnels or a combination of tunnels and penstocks.

Hydroelectric developments can generally be divided into the following components:

(1) Powerhouse
(2) Dam (or dams)
(3) Tunnels and tunnel steel liner
(4) Penstocks
(5) Intakes
(6) Turbines and generators
(7) Accessory electrical equipment
(8) Miscellaneous power plant equipment
(9) Transmission plant equipment

Each component has its own design parameters, which vary widely, with consequent wide effects on costs. In comparing hydroelectric sites, however, it is possible to screen sites by using parametric costs of the project components. In such screening, the cost of any one project might be as much as 25% above or below the parametric cost. Thus, the parametric costs are not suitable for comparing hydroelectric plants with alternative generation, but they can indicate the lowest-cost hydroelectric plants, which can be estimated in closer detail for comparison with each other and with alternative generation.

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* Adapted from ALLEN, A.E., Harza Engineering Co., "Economics of hydro and pumped storage plants", presented at IAEA Interregional Training Course on Electric System Expansion Planning, IAEA, Vienna, Div. of Nuclear Power Internal Report (1983).

The figures in this appendix (Figs I.1–9) illustrate parametric cost curves followed by explanations for their use. The parametric cost of a plant is the sum of the parametric costs for each applicable curve, plus 15% for contingencies and unforeseen items and 16% for engineering and owner's overheads.

In other words, the construction cost available from the parametric cost curves shown here is 1.31 times the sum of the components. To this should be added the costs of transmission installed specifically to utilize the plant and of interest during construction. Transmission costs depend on such factors as the owner's system voltage and location of lines and loads, so that it is difficult to generalize. Interest during construction depends on the source of funds, the situation in financial markets when plant financing is arranged, construction time, and the credit rating of the plant owner. Minimum construction time is generally two years. For projects larger than 50 MW, construction times, on the basis of experience in the USA, can be approximated as follows:

50 – 300 MW: 3 years
300 – 800 MW: 4 years
800 MW or more: 5 years

Interest during construction can be approximated as half the annual interest rate multiplied by the construction time in years, assuming linear disbursement. (Section I.3 contains a more detailed approximation, as a function of the capacity and number of units in the plant. Typical cash flow curves based on construction experience in developing countries are also shown.)

Operational considerations indicate the need for analysis in selecting generating capacity at a hydroelectric site. At any one site, parametric costs can be developed for several generating capacities. Comparison between sites may then be on a basis of capacity or energy, or both.

Since parametric costs for a project may differ by ± 25% from costs estimated more precisely, if the object of the screening process is to retain the lowest-cost plant sites it is recommended that plants be ranked on the basis of 75% of computed parametric cost, retaining all plants costing less than the justifiable amount per kW. If the screening is merely to rank plant sites in relation to each other, the parametric cost as computed can be used directly. If it is desired to evaluate the potential high cost of a plant, use 1.25 times the parametric cost estimate.

Parametric cost curves presented later in this appendix are at the cost level of January 1983. To update costs to later dates, multiply by an applicable cost index. The US Bureau of Reclamation publishes very helpful hydroelectric cost indices in January, April, July and October each year.

I.1.2. Dams and spillways

Dams may be concrete gravity, concrete arch, concrete arch and buttress, concrete slab and buttress, earth fill, rock fill, rock and earth fill, or a combination.

TABLE I.I. PARAMETRIC ADDITIONS TO DAM HEIGHT

Dam height measured on map (m)	Parametric additions to height	
	Foundation	Freeboard
30 or less	3 m	2 m
30–150	10% of measured height	The larger of 2 m or 4% of measured height
150 or more	15 m	6 m

A project may require several dams, in which case the cost of each dam must be evaluated individually.

For parametric cost purposes the cost of each dam is estimated as if it were rock fill. If subsequent studies should show that the dam was of another type, the volume of the other type would be different but the cost per unit of volume would compensate. The overall final cost of a dam that is not rock fill will differ from rock fill, but by only a reasonably small fraction.

The parametric cost of a dam is composed of two main items: the dam and the spillway. This cost is developed on the basis of the volume of the dam and a unit price covering foundation and abutment excavation, foundation and abutment treatment, coffer-dams, water diversion structures, and the dam itself. The volume of the dam is obtained from the formula:

$$\text{Volume} = 2/3 \text{ maximum cross-section} \times \text{length}$$

Length and height are measured from a map. If a dam site has obvious characteristics, such as a broad flood plain, indicating that the volume should be larger, compute the volume using several sections. To provide for foundation and freeboard the data from Table I.I are added to height as measured from the map. The parametric cross-section area of a dam based on the height adjusted in this way is obtained from Fig.I.2. The unit price applicable to the volume is obtained from Fig.I.3.

Spillway parametric cost at Jan. 1983 cost level is about US \$1415 per m^3/s. The design flood can be considered parametrically in m^3/s as 131.5 multiplied by the square root of the drainage area in km^2.

If there are several dams in a project, but not all of them require a spillway because they are on the same reservoir, the spillway cost item for dams not requiring a spillway will be zero.

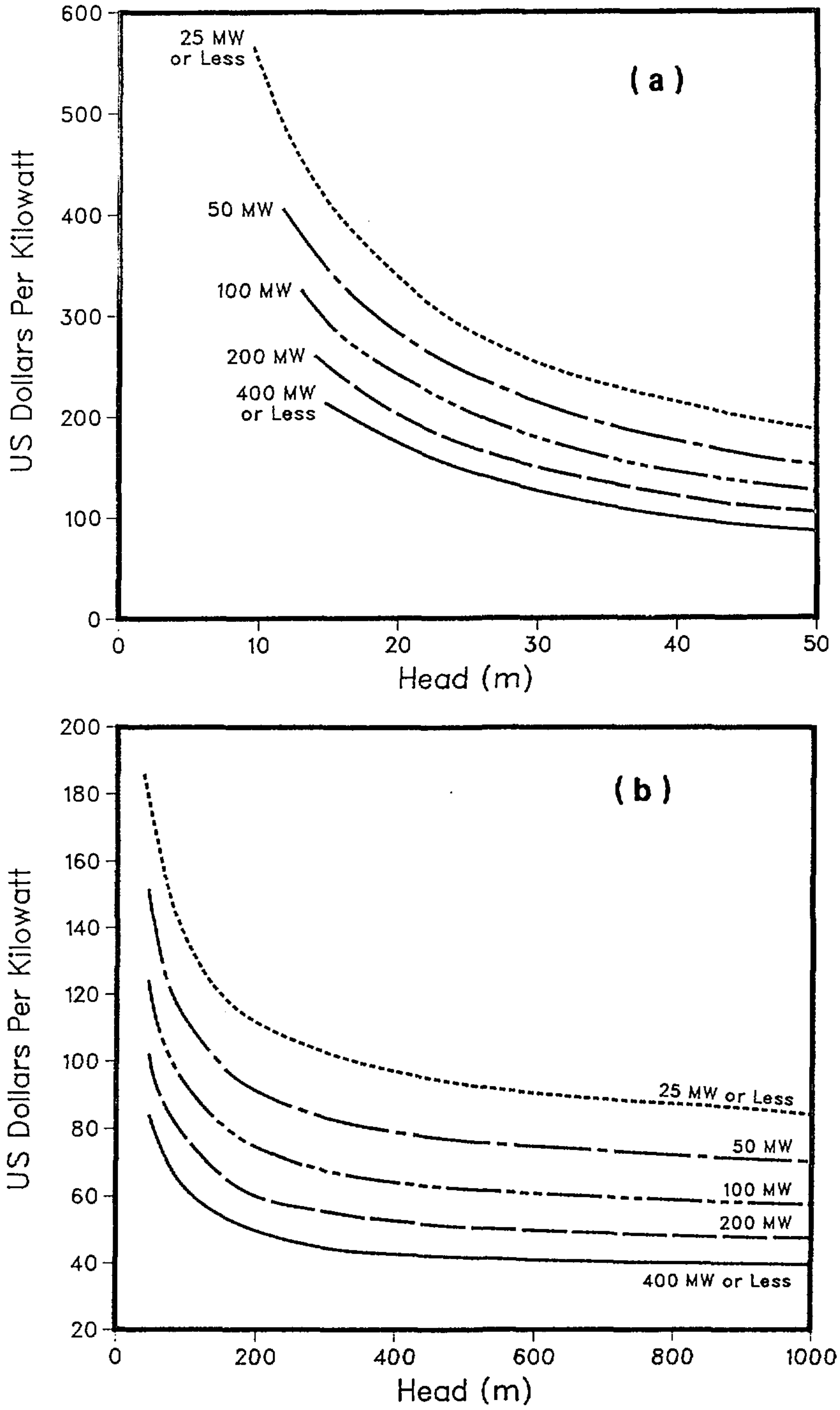

FIG.I.1. Parametric costs of powerhouse with (a) heads up to 50 m and (b) heads up to 1000 m (cost level Jan. 1983).

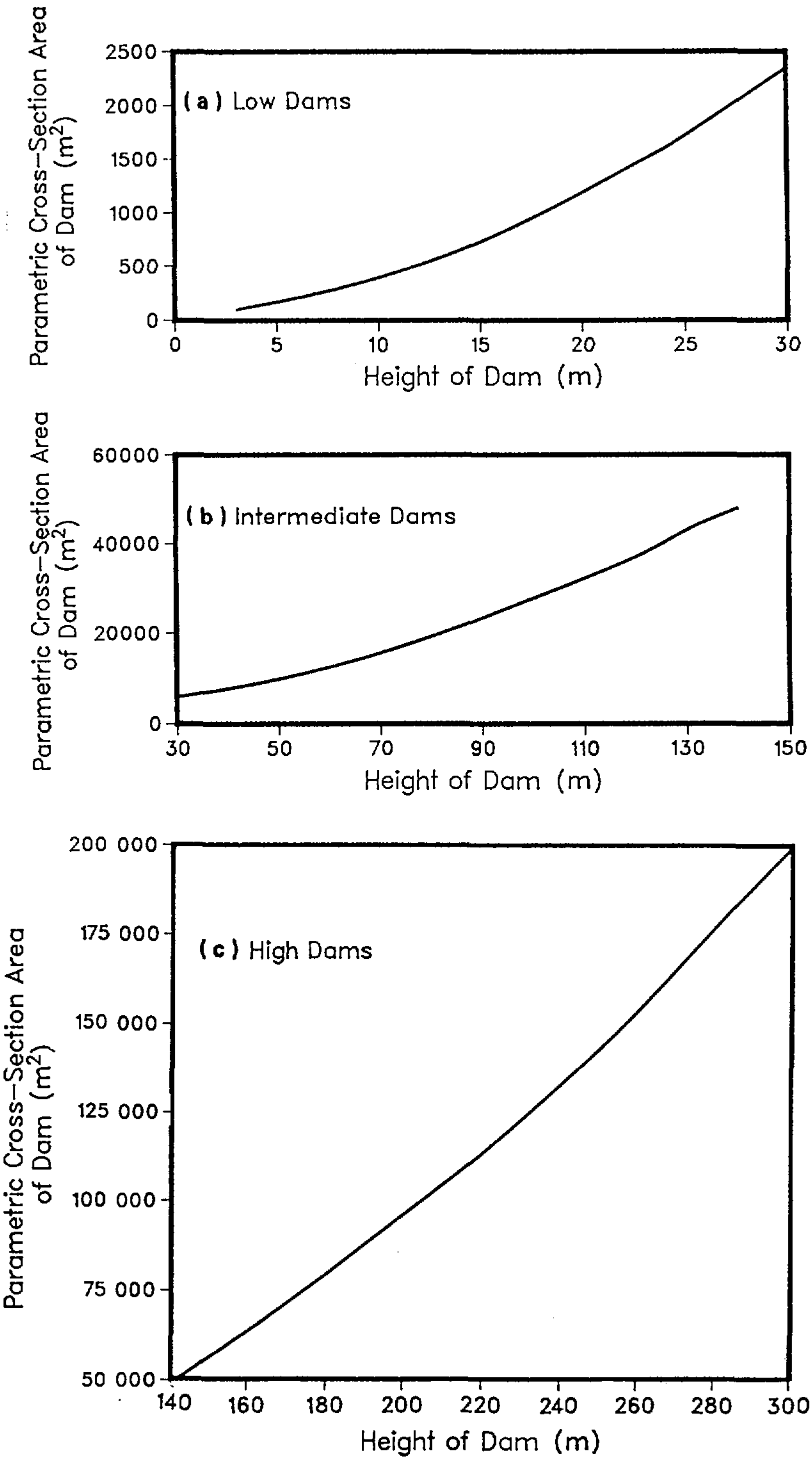

FIG.I.2. Parametric cross-section area of (a) low, (b) intermediate and (c) high dams.

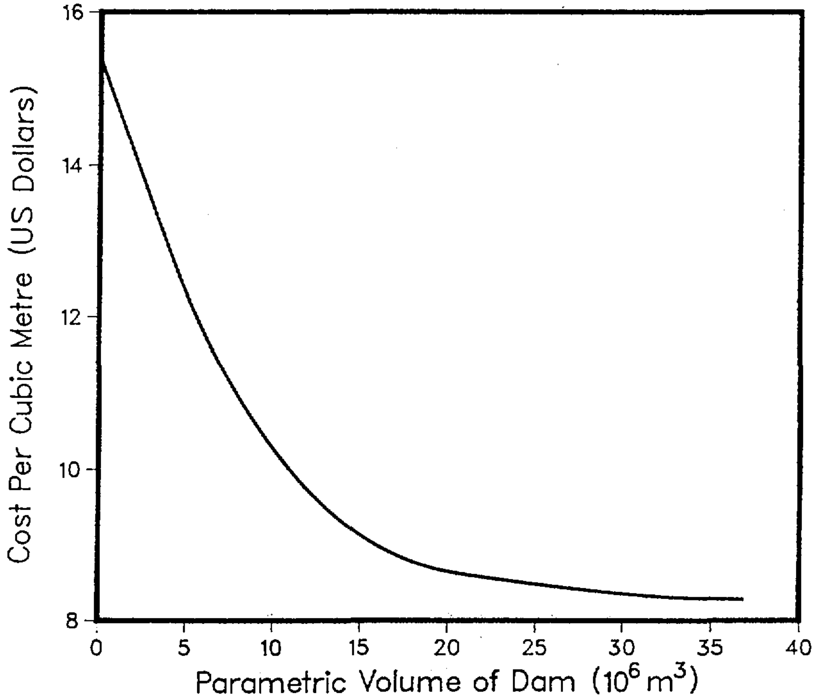

FIG.I.3. Parametric costs of dams, unit price (cost level Jan. 1983).

I.1.3. Tunnels

The parametric cost of tunnels includes the cost of excavation and concrete lining, shown in Fig.I.4, plus the cost of steel lining near the powerhouse, shown in Fig.I.5.

The first element in parametric cost estimates for tunnels is the selection of parametric water velocity in the tunnels. Conventional hydroelectric generation may occupy an important place in base load generation, and in such a situation low or moderate water velocity in the tunnel is necessary.

A conventional parameter for velocity is the ratio of project head (H) to the horizontal projection of tunnel length (L). The parametric tunnel velocity (V) in m/s is provided by the formula:

$$V = 25\left(\frac{H}{L}\right)^{0.8}$$

The parametric velocity is not more than 5 m/s and not less than 2.5 m/s. Computed velocity outside the above range should be corrected accordingly.

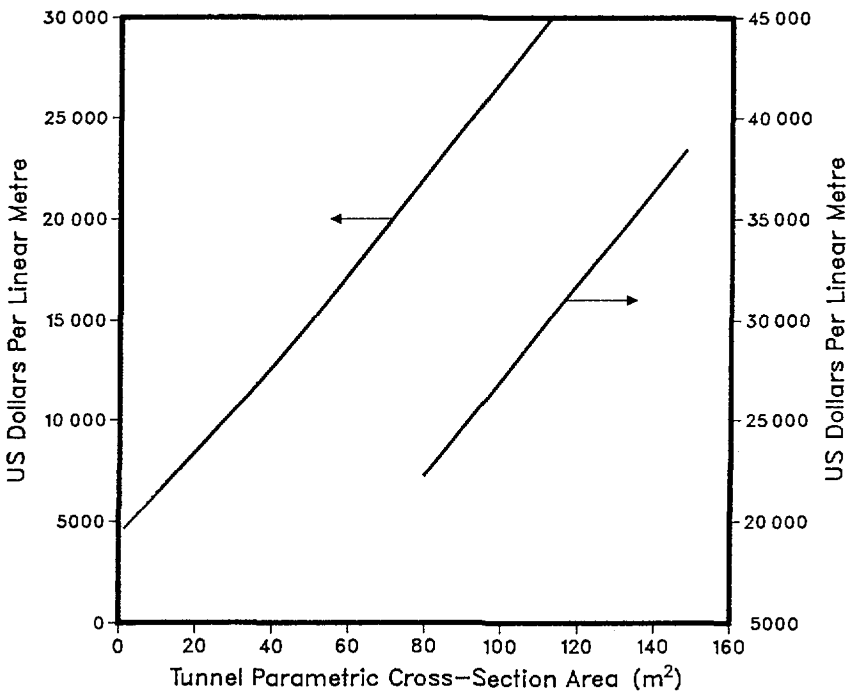

FIG.I.4. Parametric costs of tunnels (cost level Jan. 1983).

The next element is computing the tunnel parametric size from the water discharge rate used for generating power and the parametric velocity. Parametric tunnel cross-section area (A) in m^2 is obtained from the following formula:

$$A = \frac{P}{8.3\ HV}$$

where P is the generating capacity of the project, in kW, and A, H and V are as defined above and in metric units. The coefficient 8.3 assumes average generating efficiency of approximately 85%, composed of 87.6% turbine, 98% generator, and 99% transformer. Maximum efficiency is, of course, higher. The parametric tunnel cross-section area should be not more than 125 m^2 (12.6 m dia), except as adjusted for surge, as described below. If an area larger than 125 m^2 is required (before applying the surge adjustment), use two or more equal-size tunnels 12.6 m in diameter or less to obtain the necessary cross-section area.

If H/L is less than 0.1, surge control facilities are also needed. They are accounted for parametrically by increasing the tunnel cross-section area. Increase the tunnel cross-section area by 6% for each unit of 0.01 by which H/L is less than 0.1.

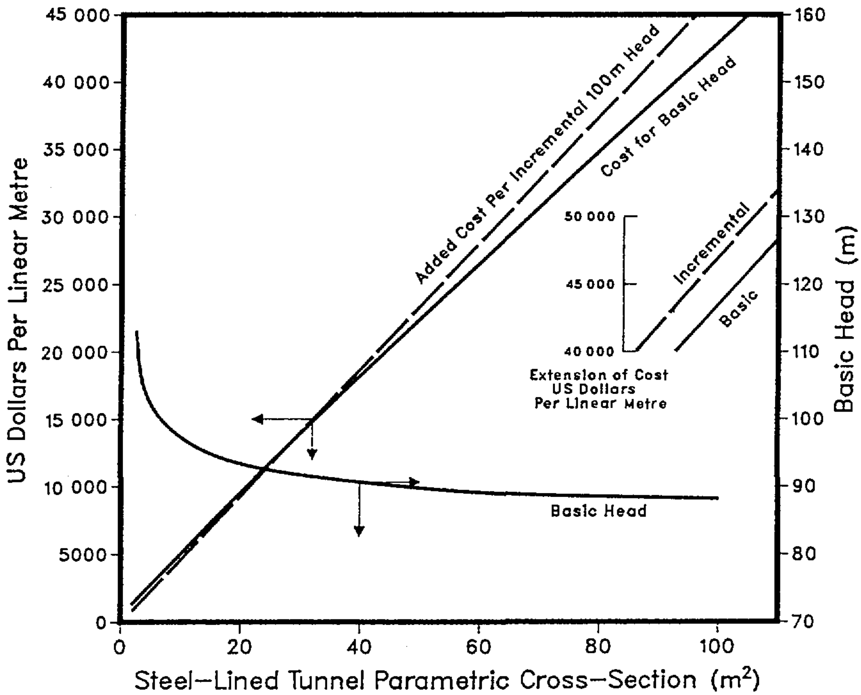

FIG.I.5. Parametric costs of steel liner of tunnels near powerhouse (cost level Jan. 1983).

When the cross-section area and number of water tunnels have been obtained, the cost per linear metre for basic excavation and concrete lining is read from Fig.I.4, and the cost of basic excavation and concrete is obtained by multiplying the cost per linear metre by the total length in metres.

Near the powerhouse there is steel liner, the cost of which should be added to the cost of basic excavation and concrete. The pressure of the water in the tunnels is at its highest intensity near the powerhouse, and the weight of overlying earth or rock to contain the pressure reduces as the powerhouse is approached. The tunnels are therefore lined with steel from the point where ground weight is insufficient to contain the pressure.

The length of the steel liner section is determined by topography and the maximum water pressure that can occur. The thickness and cost of the steel liner depend on the grade of steel, the diameter of the conduit, the water pressure, and external support conditions. The parametric cost of the steel liner is therefore difficult to derive.

The length of the steel liner section of the tunnel must be obtained from the topographic map of the project. The length of the steel liner is measured from the point where ground cover equals 60% of the project gross head to the powerhouse. To estimate the parametric cost, the cross-section or flow area of the steel liner section can be considered as 90% of the tunnel cross-section area.

Figure I.5 gives three curves for parametric cost estimates of the steel liner. For low heads there is a basic cost of the liner, which is related to the size of the waterway and minimum thickness of steel for construction handling. The basic cost is a solid line in Fig.I.5. The basic liner will provide for a project gross head in accordance with the size of the tunnel. A second solid line in Fig.I.5 shows the basic gross head provided by the minimum steel liner. If the project head exceeds the basic head, additional steel liner is required. A dashed line in Fig.I.5 shows added cost for each incremental 100 m of additional head. If the difference between project head and basic head differs from 100 m, the cost in Fig.I.5 can be multiplied by the ratio of the difference in head to 100 m. The cost of penstock valves can be considered to be included in that of the steel liner.

I.1.4. Penstocks

For situations where water is conveyed in steel pipelines not embedded in tunnels, for each metre of length use 1.5 times the cost of steel liner in Fig.I.5. In parametric cost evaluation, if open penstocks are considered, tunnel steel liner will usually not be considered. Both types may be considered for the appropriate length if the topography makes the need obvious.

I.1.5. Intakes, turbines, generators, electrical and miscellaneous power plant equipment

Figures I.6–I.9 give parametric costs for these.

I.1.6. Local transmission

Allow US $11/kW parametrically to provide for raising plant output to transmission voltage and connecting the plant to a switchyard on the transmission system.

I.1.7. Example of conventional hydroelectric plant parametric costs[1]

An example follows to show the application of different formulas and figures:

I. Basic data

(a)	River mean discharge	100 m^3/s
(b)	Dam site – map measurement	70 m high, 450 m long
(c)	Drainage area	10 000 km^2
(d)	Power tunnel	1100 m long
(e)	Project head	100 m
(f)	Turbine discharge (arbitrary)	200 m^3/s
(g)	Ground cover over tunnel (60% of head, see Section I.1.3)	60 m at point 200 m from powerhouse
(h)	River flow equalled or exceeded 42% of time	175 m^3/s

[1] Costs are in US $ for the remainder of this appendix.

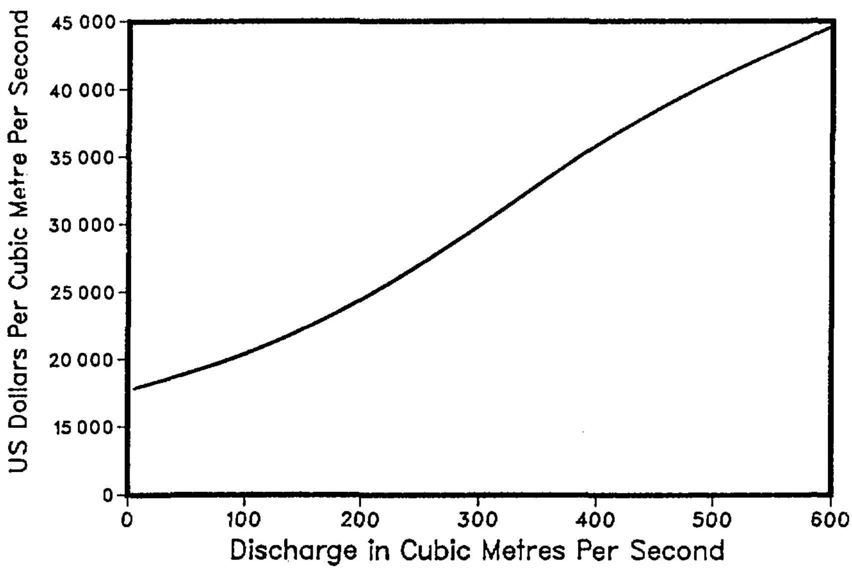

FIG.I.6. Parametric costs of intakes (cost level Jan. 1983).

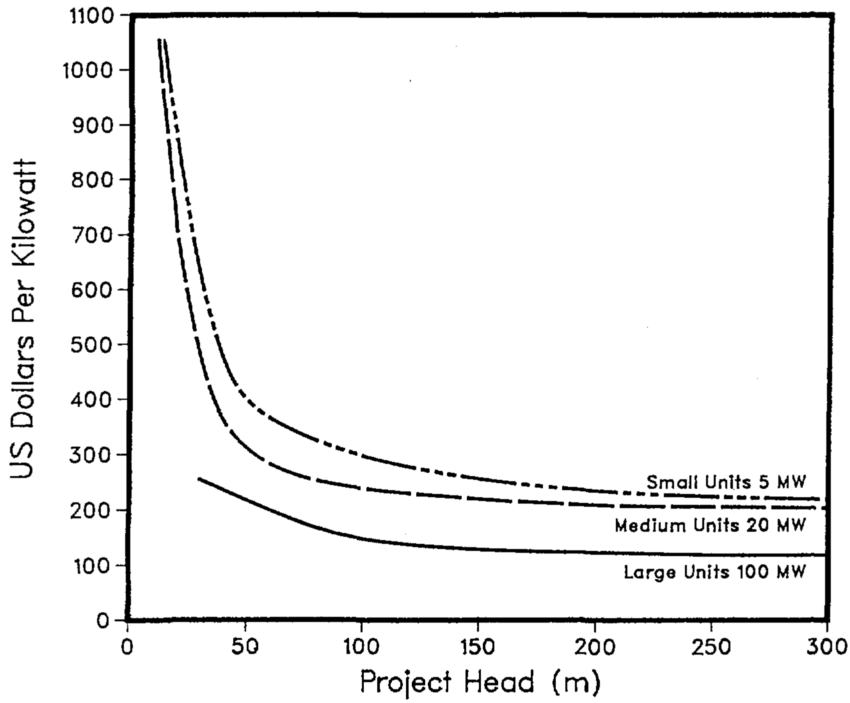

FIG.I.7. Parametric costs of turbines and generators (cost level Jan. 1983).

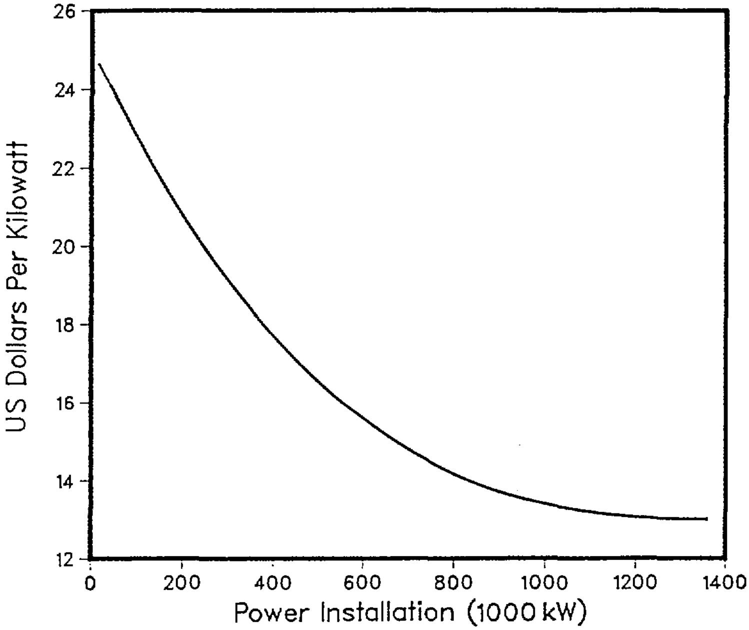

FIG.I.8. Parametric costs of accessory electrical equipment (cost level Jan. 1983).

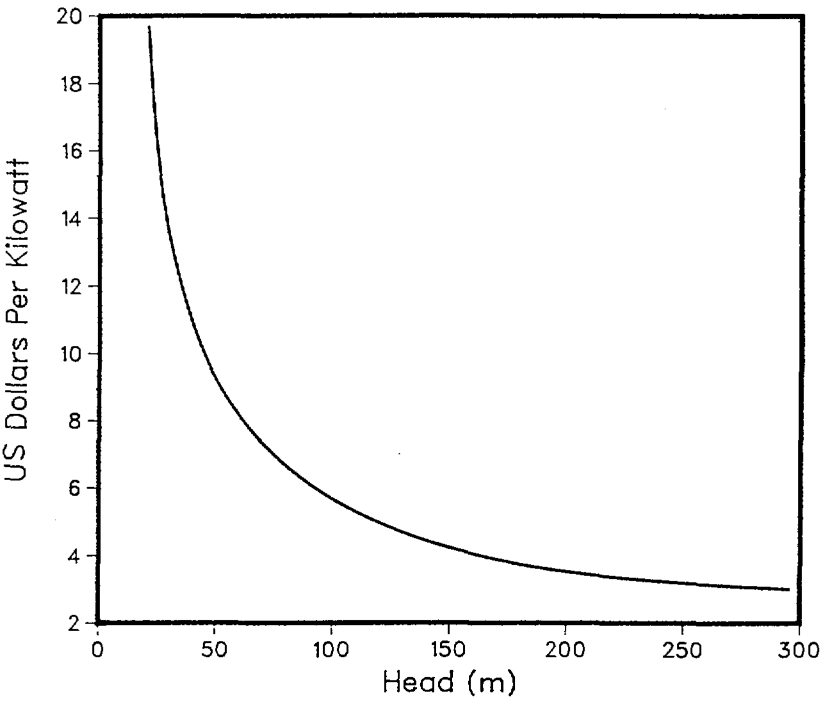

FIG.I.9. Parametric costs of miscellaneous power plant equipment (cost level Jan. 1983).

II. Project rating

0.847 efficiency (0.91 turbine; 0.98 generator; 0.99 transformer; 4% head loss)

Power developed: $8.3 \times QH = 8.3 \times 200\ m^3/s \times 100\ m = 166\,000$ kW; assume four units, each 41.5 MW

III. Parametric costs

A. *Powerhouse* (from Fig.I.1(b) and head = 100 m)
$79 per kW X 166 000 kW = $13 114 000

B. *Dam and spillway* (see Section I.1.2)

Parametric height (H)
= 70 + 7 + 2.8 = 79.8 m
Maximum cross-section (A), (Fig.I.2)
= 16 800 m^2
Parametric crest length (L)
= 450 + (2 X 9.8) = 469.6 m
Volume:
2/3 X 16 800 m^2 X 469.6 m = 5 260 000 m^3
Cost per m^3 (Fig.I.4) = $12.20
Cost of dam: $12.20 X 5 260 000 = $64 172 000
Spillway discharge:
$131.5\sqrt{10\,000} = 13\,150\ m^3/s$
Cost at $1415 per m^3/s: $1415 X 13 150 = $18 608 000

C. *Tunnel*

$$\text{Velocity (V)} = 25\left(\frac{100}{1100}\right)^{0.8} = 25\ (0.091)^{0.8}$$

$$= 25 \times 0.147 = 3.68\ m/s$$

$$\text{Cross-section area (A)} = \frac{P}{8.3\ HV} = \frac{166\,000}{8.3 \times 100 \times 3.68}$$

$$= 54.35\ m^2$$

Surge adjustment, according to previous recommendations:

$$\frac{H}{L} = \frac{100}{1100} = 0.091$$

$$0.1 - 0.091 = 0.009$$

$$\frac{0.009}{0.01} = 0.1$$

$$0.9 \times 6\% = 5.4\%$$

Adjusted area: $1.054 \times 54.35 = 57.3 \text{ m}^2$

(a) Basic tunnel cost: \$16 800/m (Fig.I.4)
$1100 \text{ m} \times \$16\,800/\text{m}$ = \$18 480 000

(b) Tunnel steel liner:
Length: 200 m
Steel liner cross-section area:
$0.9 \times 57.3 \text{ m}^2 = 51.6 \text{ m}^2$
Basic head (Fig.I.5) = 89.6 m

$$\text{Incremental} = \frac{100-89.6}{100} = 10.4\% \text{ of } 100 \text{ m}$$

Basic cost (Fig.I.5)	= \$23 100/m
Incremental cost:	
$0.104 \times \$23\,100$	= 2 400
Total cost per metre	\$25 500

Steel liner cost: $\$25\,500 \times 200 \text{ m}$ = \$5 100 000

D. Penstock

Covered by steel liner; not applicable

E. Intakes (Fig.I.6)

$200 \text{ m}^3/\text{s} \times \$24\,500$ = \$4 900 000

F. Turbines and generators (Fig.I.7)

100 m head; 41.5 MW
\$212 per kW interpolated between 20 MW and 100 MW
$166\,000 \text{ kW} \times 212$ = \$35 192 000

G. Accessory electric equipment (Fig.I.8)

166 000 kW X 21.35	= $3 544 000

H. Miscellaneous power plant equipment (Fig.I.9)

166 000 kW X $5.52	= $916 000

I. Transmission plant

166 000 kW X $11.00	= $1 826 000
Subtotal	$165 852 000
Add contingencies (15%) + engineering and owner's overhead (16%)	51 415 000
Direct construction cost	$217 267 000

J. Interest during construction

Construction time (166 MW): 3 years
Assume 8% interest rate

$$\frac{8\% \text{ per year} \times 3 \text{ years}}{2} = 12\%$$

12% X $217 267 000	= $26 072 000
Project cost	$243 339 000
Rounded	$243 000 000

$$\text{Per kW} \frac{\$243\ 000\ 000}{166\ 000} = \$1464$$

I.2. CONVENTIONAL PUMPED STORAGE COSTS

I.2.1. Cost examples

Costs for pumped storage plants vary with head, installed capacity and hours of storage. Table I.II gives examples of costs for 300 MW or more, with 10 hours of storage at 100 m or higher heads. Table I.III gives examples of costs for underground pumped storage plants for power outputs ranging from 800 to 3000 MW.

TABLE I.II. ILLUSTRATIVE COSTS FOR PUMPED STORAGE PLANTS

Plant component	Approximate cost range per kW (Jan. 1983 US $)
Land, land rights	3–32
Powerhouse	46–108
Reservoirs	94–157
Water conduits	63–189
Powerhouse equipment	106–186
Roads, access	6–21
Switchyard	15–22
Direct costs	440–620
Indirect and overhead costs	105–145
Total costs	545–765

Note: A project rarely has all components at the extreme end of the cost range.

I.2.2. Parametric cost curves for pumped storage plants

The curves and data presented for conventional hydroelectric power plants can also be used for pumped storage with the specific changes described below:

(1) *Powerhouse* (Figs I.1 (a) and (b):

Multiply reading from curve by 1.11 for pumped storage.

(2) *Dams:*

The costs of dams and spillways for conventional hydroelectric plants also apply to pumped storage. If a dam for pumped storage is not located on a river or stream, the sum of diversion and spillway discharges can be considered as the pumping capability of the plant at maximum head.

(3) *(a)* *Tunnels* (Figs I.4 and I.5):

The parametric tunnel velocity for pumped storage is given by the formula:

$$V = 27.5\left(\frac{H}{L}\right)^{0.8}$$

The parametric velocity is not more than 7.5 m/s and not less than 2.5 m/s.

TABLE I.III. UNDERGROUND PUMPED STORAGE COSTS
(For 410 m head, 2-drop, single-stage reversible Francis units, 10 hours of storage; cost level Jan. 1983)

Plant component	Approximate cost in good rock (US $/kW)		
	800 MW	2000 MW	3000 MW
Land, land rights	3	3	3
Powerhouse, including access shafts	107	67	64
Reservoirs	245	197	188
Water conduits	57	34	34
Powerhouse equipment	133	122	120
Roads, access	13	7	6
Switchyard	22	18	15
Direct costs	580	448	430
Indirect and overhead costs	254	196	188
Total costs	834	644	618

(b) Steel liner and penstocks:

For pumped storage, reduce basic head to 90% of amount read from curve. The incremental cost curve applies to 90 m incremental head for pumped storage.

(4) Intakes (Fig.I.6):

For a pumped storage reservoir with no drainage area outside itself use 50% of the intake cost from the curve. For other reservoirs use the full cost.

(5) Turbines and generators (Fig.I.7):

For pumped storage use 1.35 times the cost read from the curve.

I.2.3. Example of parametric costs for pumped storage project

An example follows to show the application of different formulas and figures:

Basic data

Lower reservoir on-stream

Drainage area: 300 km^2
Dam height (map): 35 m
Dam length (map): 250 m
Evaluation range for plant operation: 320–340 m
Useful storage: 8×10^6 m^3

River flow equalled or exceeded 42% of time: 10 m^3/s

Upper reservoir off-stream (no outside drainage area)

Dam height (map): 32 m
Dam length (map): 1200 m
Elevation range for plant operation: 590–615 m
Useful storage: $8 \times 10^6 m^3$

Tunnel length (map): 1300 m + shaft 250 m
Distance from cover of 0.6 head: $0.6 \times (615-320) = 177$ m
Distance to powerhouse: 250 m
Surface powerhouse

Project mean head

Max: $615-320 = 295$ m
Min: $590-340 = 250$ m
Mean: 272 m
Power: $8.3 \times 272 = 2260$ kW per m^3/s

Energy storage

$$\frac{8\ 000\ 000 \times 2260}{3600} = 5\ 020\ 000 \text{ kW}\cdot\text{h}$$

Plant generating rating

Assume 10 hours of storage needed

$$\frac{5020 \text{ MW}\cdot\text{h}}{10 \text{ h}} = 502 \text{ MW}$$

Pumping/generation units can be any size up to 502 MW (assume 3 units each 168 MW)

Parametric costs

(1) Powerhouse (Fig.I.1 (b)):

272 m at \$45.50 per kW
\$45.50 × 502 000 = \$22 841 000
1.11 × \$22 841 000 = \$25 354 000

(2) (a) Lower reservoir dam (Figs I.2 and I.3)

Height (map):	35 m
Parametric addition 3.5 + 2 =	5.5
Parametric height (H):	40.5 m
Length (map):	250 m
Parametric addition 2 × 5.5 =	11
Parametric length (L):	261 m

Dam volume: 2/3 × 4500 × 261 = 783 000 m^3		
Cost of dam: \$14.90 × 783 000	=	\$11 667 000
Spillway discharge: 131.5 $\sqrt{300}$ = 2280 m^3/s		
Cost of spillway: \$1415 × 2280	=	\$3 226 000
Total lower reservoir dam	=	\$14 893 000

(b) Upper reservoir dam

Height (map):	32 m
Parametric addition 3.2 + 2 =	5.2
Parametric height (H):	37.2 m
Length (map) (L):	1200 m

Parametric length = 1200 + (2 × 5.2) = 1210 m
Spillway discharge: no natural requirement
Assume spillway for inadvertent over-pumping
Assume pumping power at maximum head equals generating rating

$$Q = \frac{P}{11.3\ H} = \frac{502\ 000}{11.3 \times 295} = 151\ m^3/s$$

Dam cross-section area (Fig.I.2): 4000 m^2		
Dam volume: 2/3 × 4000 × 1210 = 3 230 000 m^3		
Cost (Fig.I.3): 3 230 000 × \$13.35	=	\$43 120 000
Spillway cost: 151 × \$1415	=	\$214 000
Total upper reservoir dam		\$43 334 000

(3) *Tunnels*

$$V = 27.5\left(\frac{H}{L}\right)^{0.8} = 27.5\left(\frac{272}{1300}\right)^{0.8}$$

$$= 27.5\ (0.209)^{0.8} = 27.5 \times 0.286 = 7.86\ \text{m/s}$$

Maximum parametric V = 7.5 m/s
Use 7.5 m/s

$$A = \frac{502\ 000}{8.3 \times 272 \times 7.5} = 29.6\ \text{m}^2$$

No surge adjustment $H/L > 0.1$
Parametric cost per linear metre: $10 750 (Fig.I.4)
(1300 + 250) m × $10 750 = $16 663 000

(4) *Steel liner* (Fig.I.5)

Cross-section area 0.9 × 29.6 ≅ 27 m^2
Basic cost per linear metre: $12 500
250 m × $12 500 = $3 125 000
Basic head: 0.9 × 91.8 m = 82.6 m
Remaining head: 295–82.6 = 212.4 m
212.4 ÷ 90 m = 2.36 incremental units
Incremental cost per linear metre: $12 500
250 m × 2.36 × $12 500 = $7 375 000

(5) *Intakes* (Fig.I.6)

Lower reservoir:
  $Q = AV = 29.6 \times 7.5 = 222\ m^3/s$
Cost per m^3/s: $25 000
  222 × $25 000 = $5 550 000
Upper reservoir:
  Cost per m^3/s: 0.5 × $25 000 = $12 500
  222 × $12 500 = $2 775 000

(6) *Turbines and generators* (Fig.I.7)

Cost: 130 × 1.35 = $175.50/kW
$175.50 × 502 000 kW = $88 101 000

(7) *Accessory electrical equipment* (Fig.I.8)

Cost per kW: \$16.60
\$16.60 X 502 000 kW = \$8 333 000

(8) *Miscellaneous power plant equipment* (Fig. I.9)

Cost per kW: \$3.10
\$3.10 X 502 000 kW = \$1 556 000

(9) *Transmission plant equipment*

\$11 per kW X 502 000 kW = \$5 522 000

Subtotal	\$222 581 000
+ 31%	\$69 000 000
Direct construction cost	\$291 581 000

Construction time: 4 years

Interest rate assumed 8%

Interest during construction:

$$\frac{8\% \text{ per year} \times 4 \text{ years}}{2} = 16\%$$

0.16 X \$291 581 000	\$46 652 000
Project cost	\$338 233 000
Project cost rounded	\$338 000 000
Cost per kW	\$675

I.3. INTEREST DURING CONSTRUCTION (IDC)

Table I.IV gives a detailed approximation for calculating IDC as a function of the capacity and number of units in the plant. Typical cash flow curves, based on construction experience in developing countries, are given in Table I.V.

Interest during construction, as understood here for application in the studies of hydroelectric plants, is the financial charge on the invested capital. It is calculated by applying a specified interest rate to the time schedule of disbursement of the invested capital.

TABLE I.V. CASH FLOW FOR VARIOUS DISBURSEMENT CURVES

Curve \ Year	X[a] – 6	X – 5	X – 4	X – 3	X – 2	X – 1	X	X + 1	X + 2	X + 3	X + 4	X + 5	X + 6	X + 7	Total (%)
A	–	1	4	18	31	31	15	–	–	–	–	–	–	–	100
B	–	1	4	18	30	30	13	4	–	–	–	–	–	–	100
C	–	1	4	18	30	30	12	3	2	–	–	–	–	–	100
D	2	7	17	21	21	20	9	3	–	–	–	–	–	–	100
E	2	7	17	18	19	19	9	7	2	–	–	–	–	–	100
F	2	7	17	18	19	19	8	5	4	1	–	–	–	–	100
G	2	7	15	17	18	18	8	5	4	3	2	1	–	–	100
H	2	7	15	17	17	17	8	5	4	3	2	1	1	1	100

[a] X = Year of commissioning of the first unit.

TABLE I.IV. INTEREST DURING CONSTRUCTION (IDC) FOR VARIOUS DISBURSEMENT CURVES

Capacity	Disbursement curve	No. of units	IDC (%)		
			I = 10%	I = 11%	I = 12%
	A	2	19	21	23
≤ 500 MW	B	4	19	21	23
	C	8	19	21	23
	D	4	28	31	34
	E	8	27	30	33
≥ 500 MW	F	12	27	30	33
	G	20	25	28	31
	H	26	25	28	31

The approach adopted for estimating the interest during construction is to spread the costs according to a construction schedule and to apply the interest rate to the cumulative costs up to the end of each year. The value of interest during construction for the first year is considered part of cumulated costs when calculating the interest for the second year (i.e. interest is compound) and so on until the year of commissioning of the first turbo-generator unit.

After commissioning of the first unit, interest is calculated only on the additional investment costs for future units. When each unit is commissioned, its cost is withdrawn from the total so that the rest of the interest during construction can be calculated. Hence, interest during construction is calculated on an increasing cumulative value up to the commissioning of the first turbo-generator and is based on a decreasing value from this date on.

For hydroelectric plants with more than one unit, it is considered necessary to use the major part of the investment cost to put the first unit into operation. Hence, the costs of dams, dykes, forebays, etc., are considered part of the investment cost of the first unit.

A reasonable estimate of the IDC for hydroelectric plants, based on the above assumptions, is given in Tables I.IV and I.V.

Appendix J

DATA REQUIRED FOR A TYPICAL ELECTRIC SYSTEM EXPANSION STUDY

The complexity of the type of analysis applied for the expansion of a power system requires the availability of a large amount of information concerning the system considered and the economic conditions of the country (or region). For accurate results, this information should be as reliable as possible. It should also be future-oriented so as to represent the conditions in which the proposed system is expected to operate. The data fall into the following categories:

- Forecast of future electricity demand, possibly interacting with total energy demand;
- Thorough knowledge of the technical characteristics and generating costs of each of the generating units of the system in operation, under construction or committed;
- Estimate of the indigenous resources (e.g. hydroelectric, gas, coal) available for future electricity production, and definition of the alternative imported energy sources that can be considered;
- Estimate of the technical and economic data of plants to be considered as expansion alternatives;
- Knowledge of system reliability, criteria and operating practices;
- Economic parameters such as interest and discount rates, shadow exchange rate.

A wide range of information is required in order to determine the actual data for each of these categories. Estimating the economic data for 'alternative' power plants is a good example, since the data needed for this category are: plant investment cost, fuel cost and other O&M costs – all dependent on plant location. This usually requires, first, gathering cost experience observed for similar plants, perhaps in other countries or regions, and then extrapolating it with respect to time, unit size and economic conditions, taking into account the location of the plant. Appropriate weight must be given, for example, to the following:

- Availability of fuel and transport;
- Impact of the location on additional transmission system requirements (transmission lines, substations);
- Environmental protection (need for cooling towers, flue gas desulphurization system);
- Local labour wages and salaries.

This list of basic data categories must be enlarged to include other information required for closer analysis of the proposed system, e.g. financial analysis, frequency stability, manpower requirements.

The type of data required for an electric system expansion study is, to a certain extent, independent of the computer program to be used for the study. There are, however, differences between the available programs which impose specific requirements on the input data in each case. These differences refer to the modelling of both the load and the types of power plant permitted, the treatment of scheduled and forced outages of these plants, the economic criterion selected for comparing alternative expansion policies, etc. Furthermore, the internal equations considered by each program and its corresponding output units require the input data to be provided in a determined set of units.

It is obvious that it is difficult to prepare a comprehensive list of all possible data required by the available computer programs for electric system expansion planning. The following list of information is therefore based on the execution of a typical study by means of the WASP computer code. When applicable, the input data units are presented as required by WASP. This list of data has been expanded to include complementary information required either for some other analysis considered by the WASP methodology or for preparing the report of the study. (See, particularly, Chapter 11, which describes the WASP program.)

J.1. BACKGROUND INFORMATION

1.1. Past and projected population.
1.2. Past and projected gross national product (GNP) broken down by economic sectors (industry, mining, etc.), and other economic information of interest (main products, imports/exports, etc.).
1.3. National energy resources (hydroelectric potential, fossil fuels, uranium, geothermal, etc.).
1.4. Past and projected total energy consumption, if possible broken down by sectors (industrial, residential, services, etc.).
1.5. Interest and organizational structure for introduction of nuclear power.

J.2. ELECTRICITY SYSTEM DEMAND INFORMATION

2.1. Historical development of interconnected system load and installed capacity (thermal, hydroelectric and total) by year (for 10 or more years).

(a) Installed capacity (MW);
(b) Gross energy generation (GW·h) broken down into hydroelectric and thermal generation;
(c) Annual peak load (MW);

(d) Seasonal variation of the peak load: period[1] peak load (expressed as a fraction of the annual peak);
(e) Load duration data for the period[1] (tables or graphs showing percentage of peak demand versus percentage of time).

2.2. Forecast of electricity demand for the years (up to 30) of the study period.

(a) Basis for the forecast;
(b) Forecast annual electricity generation (GW·h) and peak demand (MW);
(c) Projected changes in seasonal characteristics of the load, specifying in each case the new information on monthly or quarterly peak load and the load duration data.

J.3. HYDROELECTRIC POWER

Hydroelectric and/or pumped storage projects may be considered in the study. These projects may be classified either as DECIDED (projects in operation, under construction, or committed) or UNDECIDED (projects which might be developed during the study period and thus considered as candidates for system expansion).

3.1. Characteristics of each hydroelectric project

(a) Map showing major river systems and locations of stations.
(b) Name of plant.
(c) Plant type (run-of-river, seasonal storage, daily or weekly regulation, multi-purpose, etc.).
(d) Volume of upper reservoir (GW·h) and past or projected practices for use of the available volume of large reservoirs (i.e. those capable of performing regulating duties from season to season).
(e) Number of generating units in each station and capacity (MW) of each. Net head (m) of the power plant and maximum flow for each turbine (m^3/s).
(f) Historical (for DECIDED projects) or estimated (for UNDECIDED projects) monthly or quarterly and annual gross energy generation (GW·h).
(g) Historical seasonal water inflow conditions (m^3/s).
(h) Historical (for DECIDED projects) or estimated (for UNDECIDED projects) seasonal variation of net head (m) and capacity (MW) of the station.

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[1] For a WASP study, each year may be subdivided into an equal number of periods (up to 12). Thus the seasonal variation of the load characteristics may be expressed monthly, bimonthly, quarterly, etc.

(i) Date of commissioning (for DECIDED projects) or earliest date of commissioning (for UNDECIDED projects).
(j) O&M costs broken down into fixed component (US$/kW-month) and variable component (US $/MW·h).
(k) Estimated plant life (years).
(l) Estimated cost to develop the plant and time of construction (for UNDECIDED projects only).

Note: Data (e)–(g) should be given for as many years as possible or, preferably, for predetermined hydrological conditions (up to five) of annual rainfall (e.g. average, dry and wet years) and the corresponding probability of occurrence of each year defined.

3.2. Characteristics of each pumped storage project

(a) Map showing locations of stations;
(b) Name of plant;
(c) Pumping power requirements (MW) and pumping efficiency (%);
(d) Generator power capacity (MW) and efficiency (%);
(e) Operation cycle (proposed cycle for UNDECIDED projects) including maximum feasible energy per cycle or maximum number of hours per day;
(f) Date of commissioning (earliest date for UNDECIDED projects);
(g) O&M costs, fixed (US $/kW-month) and variable (US $/MW·h);
(h) Estimated plant life (years).
(i) Estimated cost to develop and construction time (for UNDECIDED projects only).

J.4. CHARACTERISTICS OF THERMAL POWER PLANTS EXISTING, UNDER CONSTRUCTION, COMMITTED AND PLANNED

4.1. Technical data

(a) Map showing location of all thermal stations and their relationship to the interconnected transmission system;
(b) Name of each plant;
(c) Type(s) of fuel burnt;
(d) Fuel calorific value (kcal/kg);
(e) Number of identical units in the station, and for each unit:
- Rated (nameplate) capacity (MW),
- Minimum operating level (MW),
- Heat rate at full (rated) load and at minimum load (kcal/kW·h),
- Admissible overload (percentage of full load),
- Forced outage rate (FOR) (%),
- Maintenance requirements (days per year).

4.2. Economic data

(a) Fuel cost at plant site;
(b) Non-fuel O&M costs, in fixed (US \$/kW-month) and variable (US \$/kW·h) components;
(c) Date of commissioning each unit (for additions, if any) and estimated economic life of the unit (for retirements, if any);
(d) Estimated capital investment cost and construction time.

J.5. ECONOMIC GROUND RULES AND CONSTRAINTS TO BE CONSIDERED IN THE STUDY

(a) Interest rate in the absence of inflation (%/year);
(b) Discount rate in the absence of inflation (%/year);
(c) Foreign exchange rate (local currency per US \$) and penalization (if any) applicable to expenditure in foreign currency;
(d) Cost to be charged to unsupplied electrical energy (US \$/kW·h) and, if possible, the variation of this cost with the relative amount of unsupplied energy to total system energy demand;
(e) Estimated participation of local industry in the construction of power plants of the types considered in the study;
(f) Social, economic, financial and any other recognizable constraints applicable to the construction of new power plants in the country (or region).

J.6. TRANSMISSION SYSTEM

6.1. A map showing the existing interconnected systems and the committed and planned expansions;

6.2. A list of the existing, committed and planned major transmission lines (for bulk power transmission) containing their main characteristics, e.g. name, voltage (kV), length (km) and thermal limit (MVA).

J.7. SYSTEM OPERATING PRACTICES AND CRITERIA FOR SYSTEM RELIABILITY

7.1. Reserve margins over system peak load;
7.2. Acceptable limit for the loss of load probability (LOLP), the fraction of time in which the load demand may exceed available generation capacity;

7.3. Frequency stability considerations, specifying the following:

(a) Maximum allowable frequency deviation (Hz);
(b) Load shedding practices, including frequency deviation values (Hz) at which load should be shed and the block of load shed (MW).

J.8. CHARACTERISTICS OF FUELS FOR POWER PRODUCTION

8.1. Indigenous fossil fuels (coal, lignite, oil, gas)

For each fuel specify the following:

(a) Past and projected consumption for power production;
(b) Current and projected costs of fuel delivered to the power plant;
(c) Country's policies regarding use of fuels for power production (e.g. environmental considerations, use for other purposes, priorities assigned to the use of certain fuels).

8.2. Imported fossil fuels

For each fuel specify the following:

(a) Past and projected imports of the fuel (for oil include crude and/or residual oil and/or light distillates) for power production,
(b) Projected costs in harbour and delivered to utilities.

8.3. Uranium

(a) Amount and location of reserves (tonnes of ore with specified amounts of U_3O_8),
(b) Estimated costs,
(c) Plans for developing uranium industry,
(d) Exploration activities under way or planned.

8.4. Infrastructure

For each category and type of fuel mentioned above, list the appropriate infrastructure (e.g. harbours, roads, trains) that is (or will be) available for handling it, with special remarks about additional infrastructure that may be needed.

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GLOSSARY

The following definitions are intended for use with this guidebook and may not necessarily conform to definitions adopted elsewhere for international use..

allowance for funds used during construction (AFUDC) (see **interest during construction (IDC)**).

amortization. (1) As applied to a capitalized asset, the distribution of the initial cost by periodic charges to operations as in depreciation; most properly applies to assets with indefinite life. (2) The reduction of a debt by either periodic or irregular payments. (3) A plan to pay off a financial obligation according to some prearranged schedule.

annuity. (1) An amount of money payable to a beneficiary at regular intervals for a prescribed period of time out of a fund reserved for that purpose. (2) A series of equal payments occurring at equal periods of time.

available capacity. The available capacity (in MW) at a given moment is the maximum capacity at which the station can be or is authorized to be operated at a continuous rating under the prevailing conditions assuming unlimited transmission facilities.

average annual cost. The conversion, by an interest rate and present worth technique, of all capital and operating costs to a series of equal payments occurring at equal periods of time.

average load. The hypothetical constant load over a specified time period that would produce the same energy as the actual load would produce for the same period.

average power demand. The demand (in kW) on an electric system or any of its parts over any interval of time, as determined by dividing the total number of kW·h by the number of units of time in the interval. (See **average load.**)

back end of the (nuclear) fuel cycle. Includes such costs as spent fuel storage, transport, fuel reprocessing and waste management.

base cost. (Capital investment) equals direct plus indirect cost. (See **fore cost.**)

base load. The minimum load over a given period of time.

base load capacity. Generating capacity operated to serve base load.

bituminous coal. Soft coal with a heating value of 25.6 to 32.6 MJ/kg (11 000 to 14 000 Btu/lb). Bituminous coal is high in ash and in carbonaceous and volatile matter. When volatile matter is removed by heating in the absence of air the coal becomes coke.

boiling water reactor (BWR). A nuclear reactor in which water, used as both coolant and moderator, is allowed to boil in the reactor core. The resulting steam can be used directly to drive a turbine for electricity generation.

breeder reactor. A nuclear reactor in which energy is released by fission while, at the same time, more fissile material is produced than is consumed. In addition to the fissile material, a breeder contains a fertile material which is converted into fissile material as a result of capturing neutrons in the reactor. In a breeder, the ratio of fissile nuclei produced from the fertile material to the fissile nuclei consumed in fission and non-fission reactions, called the *breeding ratio,* must be greater than one. If it is less than one, the reactor would be a converter. The two principal types of breeder reactor are the liquid-metal fast breeder (LMFBR) and the gas-cooled fast breeder (GCBR).

breeding ratio (see **breeder reactor**).

bus bar. An electrical conductor in the form of rigid bars located in a switchyard or in power plants, serving as a common connection for two or more electrical circuits.

capacity (of a power plant). The electric power for which a generating unit or station is rated under the specific conditions defined by the manufacturer (in MW(e)).

capacity factor (CF) (%). $CF = E \times 100/(P_n \times H)$, where E = net energy produced (MW·h(e)), P_n = maximum net capacity (MW(e)), and H = number of hours in the reference period. The capacity factor for a unit or station for a given period of time is the ratio of the energy that it produced during the period considered to the energy that it could have produced at maximum capacity under continuous operation during the whole of that period.

capital, direct. Cost of all material, equipment and labour involved in the fabrication, installation and erection of facilities.

capital, indirect. Costs associated with construction but not directly related to fabrication, installation and erection of facilities. Can be broken down into field costs (temporary structures, field supervision) and office costs (engineering, drafting, purchasing and office overhead expenses).

capital recovery factor. A factor used to calculate the sum of money required at the end of each of a series of periods to regain the net investment of a project plus the compound interest on the unrecovered balance.

cash flow. The movement of money, either into the project (called revenues) or out of the project (called disbursements).

civil engineering accessories. Gates, spillways, grates to prevent the passage of floating solids, etc. (hydroelectric power plant).

class of service. Defines the types of customer. The common classes of service apply to ultimate consumers. Every country has its own definition of class of service in order to group common types of services. One example of grouping is the following:

(1) *residential service.* Covers service to customers for domestic purposes (single, multifamily or mobile homes, etc.). In residential service, the number of housing units within a structure determines the customer classification.

(2) *commercial service.* Covers service to customers engaged in wholesale or retail trade, agriculture, communications, finance, fisheries, forestry, government, insurance, real estate, transport, etc., and to customers not directly involved in other classes of service.

(3) *industrial service.* Covers service to customers engaged primarily in a process which either involves the extraction of raw materials from the earth or a change of raw or unfinished materials into another form or product. Some countries include agriculture and fishing activities in the industrial service class.

(4) *other services.* Service to municipalities or agencies of state or federal government under special contracts or agreements of service classification which are applicable only to public authorities.

(5) *sales for resale.* Service to other utility companies, government agencies (municipal, county, state or federal), rural co-operatives, etc., for distribution and resale to ultimate consumers. Service to other utilities, for use by them and not for distribution and resale, is usually classified as residential, commercial or industrial depending on the primary business or economic activity.

coal gasification. A general term used to describe the production of fuel gas from coal.

coal liquefaction. A general term used to describe conversion of coal into a mixture of liquid hydrocarbons.

commercial operation date. The date when a unit/plant is declared to be available for regular production of electricity.

conduit conduction system. A canal or tunnel that takes water from the intake to the forebay (hydroelectric power plant).

constant money. Monetary units of a constant purchasing value. The particular purchasing value chosen is that of the reference date.

constant money analysis. An analysis made without including the effect of inflation although real escalation is included. The discount rate in the absence of inflation must be used.

construction cost. The sum of all costs, direct or indirect, inherent in converting a design plan for material and equipment into a project ready for operation, i.e. a sum of field labour, supervision, administration, tools, field office expense and field-purchased material costs.

contingencies. Specific provision for unforeseeable elements of cost within the defined project scope.

cooling tower. A structure for transferring heat to the atmosphere from water that has been warmed in a heat removal process; the water is thus cooled for reuse. Cooling towers are frequently used in closed-cycle (or circulating) condenser cooling systems for steam turbines in electric power generation plants. In these systems, the warmed water leaving the condenser passes through a cooling tower where heat is removed; the cooled water is then recirculated to the condenser. There are three general types of cooling tower: wet, dry and wet/dry. In wet towers, also called evaporative towers, the air and the water to be cooled are in contact. Cooling is caused mainly by evaporation of the water and partly by direct heat transfer. In dry (or non-evaporative) towers, the water or steam to be cooled and the air are not in direct contact and cooling results entirely by the transfer of heat across a separating surface. A wet/dry tower has a wet section and a dry section which can be combined in various ways.

cost-benefit analysis. A systematic examination of the positive effects (benefits) and negative effects (costs) of undertaking an action.

cost index (price index). A number which relates the cost of an item at a specific time to the corresponding cost at some arbitrarily specified time in the past.

critical streamflow. The amount of streamflow available for hydroelectric power generation during the most adverse streamflow period.

current money *or* **mixed-years money.** As related to investment cost, it is the arithmetical sum of monetary units spent in different years. The sum is mixed because it is a sum of money of different purchasing values. The monetary units are 'current' because they were spent according to their then current value.

current money analysis. An analysis that includes the effect of inflation and real escalation.

dam. A structure built across the main watercourse to store and/or raise the level of water.

declining balance depreciation. A method of computing depreciation in which the annual charge is a fixed percentage of the depreciated book value at the beginning of the year to which the depreciation applies.

decommissioning. The work required for the planned permanent retirement of a nuclear facility from active service.

demand. The rate at which energy is required by a customer or by a system. The electric demand, in particular, is expressed in kW, kV·A, or other suitable units, at a given instant or average over any designated time.

demand factor. (1) The ratio of the maximum instantaneous production rate to the production rate for which the equipment was designed. (2) The ratio between the maximum power demand and the total connected load of the system.

depreciation. (1) Decline in value of a capitalized asset. (2) A form of capital recovery applicable to a property with two or more years' lifespan, in which an appropriate portion of the asset's value is periodically charged to current operations.

deterministic analysis. A classical technique for studying a system behaviour mathematically using the laws of science and engineering provided that all system parameters, events and features are defined deterministically (as opposed to probabilistically).

diesel engine. An internal combustion engine in which the fuel is ignited by injecting it into air that has been heated to a high temperature by rapid compression; hence, diesel engines are also called compression-ignition engines.

direct costs. The direct capital cost of a power plant includes those costs associated with the purchase and installation of plant components. It consists of the factory equipment costs and the site installation costs. The latter include the site labour costs (which in turn include both the wages and the benefits for the labour force) and the costs of installation materials (e.g. welding material, reinforcement rods, wiring).

discount rate. The rate of interest reflecting the time value of money that is used to convert benefits and costs occurring at different times to equivalent values at a common time. Theoretically, it reflects the opportunity cost of money to a particular investor (or, in broad terms, in a particular country).

dispatching. The operating control of an integrated electric system involving operations such as:

(1) Assignment of levels of output to specific generating stations and other sources of supply to effect the most reliable and economical supply as the total load rises or falls.

(2) Control of operation of high-voltage lines, substations and equipment.
(3) Operation of principal tielines and switching.
(4) Scheduling of energy transactions with connecting electric utilities.

ecosphere. That portion of the Earth which includes the biosphere and all the ecological factors which operate on the living organisms it contains.

ecosystem. A natural complex of plant and animal populations and the particular sets of physical conditions under which they exist; the organisms of a locality, together with the functionally related aspects of environment considered as a single entity.

effluent. A fluid (liquid or gas) which is discharged into the environment.

electro-mechanical accessories. Main valve (gate or butterfly); turbo-generator transmission by direct coupling or by transmission systems (V-belt, chain or gears); hydraulic instrumentation (manometers); lightning conductors, and so on (hydroelectric power plant).

energy. The capacity for performing work. The term generally used for electricity is kW·h and represents power (kW) operating for some period of time (h).

energy consumption. The fuel and electricity delivered to consumers; it is the quantity of energy that the consumer (an industrial plant, a household, a shop, etc.) is billed for by a supplier.

exclusion area. A term used in some countries to designate a zone which may be established round a nuclear facility or other radiation source, to which access is permitted under controlled conditions and in which residence is normally prohibited.

expected loss of load (XLOL). Indicates the expected magnitude of the unsupplied load (in MW) given that a failure has occurred.

expected unserved energy (EUE). The expected amount of energy not supplied per year owing to generating capacity deficiencies and/or shortages in basic energy supplies.

fertile material. One of several nuclides (principally ^{238}U and ^{232}Th) capable of being transformed, directly or indirectly, into a fissile nuclide by neutron capture.

field costs. Engineering and construction costs associated with the construction site rather than the home office.

firm power *or* **primary power.** That load, within a hydroelectric plant's capacity and characteristics, that may be supplied virtually at all times. It is determined by the minimum streamflow and the amount of regulating storage available.

fissile material. A (radioactive) material containing one or more fissile nuclides.

fissile nuclide. A nuclide capable of undergoing fission by interaction with neutrons of any energy. For reactors, fissile nuclides of major interest are ^{235}U and ^{239}Pu.

fission. The splitting of a heavy nucleus into two parts (which are radioactive nuclei of lighter elements), accompanied by the release of a relatively large amount of energy and generally one or more neutrons.

fission product. A nuclide produced either by fission or by the subsequent radioactive decay of a radioactive nuclide thus formed.

fixed charge rate. Associated with a certain investment, it is the annual expense related to the investment expressed as a percentage of initial investment. Generally, the fixed charges consist of the interest on capital, the rate of recovery of capital, taxes (where appropriate), and insurance (where appropriate).

fixed costs. Those costs independent of short-term variations in output of the system under consideration. Includes such costs as labour, maintenance, technical service and laboratory expenses, taxes and insurance, plant overheads and administration.

flue gas desulphurization (FGD). Encompasses all those components needed to remove SO_2 from the flue gas. As such, it includes the sorbent (usually lime or limestone) handling and preparation facilities, the scrubber modules (consisting principally of a spray tower and mist eliminator), a heating system for reheating the cleaned gas prior to discharge, a sludge disposal system, and all the ductwork, pumps, fans, etc., that would not be needed if an FGD system were not used.

fluidized bed technology. Technology to suspend solid particles in a loose bed of material by a rapidly moving upward stream of gas in order to enhance chemical or physical reaction.

forced outage. A sudden unplanned loss of either generating capacity or power supply to a transmission grid.

forced outage rate. The percentage of scheduled generating time a unit is unable to generate because of forced outages due to mechanical, electrical or other failure.

forebay. Structure that facilitates the entry of water to the penstock (hydroelectric power plant).

fore cost. The overnight construction costs of a power generation facility, including all direct and indirect costs, owner's costs and commissioning expenses, spare parts and contingencies. These costs exclude escalation and interest charges. (See **overnight costs.**)

fossil fuels. Coal, oil and natural gas.

free on board (FOB). Indicates that the price includes loading on board ship but does not include the cost of insurance or passage to its intended destination.

frequency and duration of failures to meet the load (F&D). The *frequency* of generating capacity shortage events is defined as the expected (probability-weighted average) number of events per year, while the *duration* is the expected length of capacity shortage periods when they occur.

front end of the nuclear fuel cycle. Those activities involving the preparation of nuclear fuel, ranging from exploration for natural uranium to the fabrication of nuclear fuel assemblies, and delivery of the fuel assemblies to the power plant.

fuel costs (fuel cycle costs). Those charges that must be recovered in order to meet all expenses associated with consuming and owning fuel in a power plant.

fuel rate. The amount of fuel needed to generate 1 kW·h of electricity.

generating capability. The maximum load which a generating system can supply under specified conditions for a given period of time.

generation, electric. The process of transforming other forms of energy into electric energy.

generator. A machine that converts mechanical energy into electrical energy.

grid. The transmission network interconnecting electric power systems or bulk power components of a single system.

gross capacity. Corresponds to the electric output at the terminals of the generator sets in the station; it therefore includes the power taken by the station auxiliaries and losses in transformers that are considered integral parts of the station.

gross head. Difference in level (metres) from the upper surface of the water at the highest usable point to the lower level of its use by the turbine (hydroelectric power plant).

gross national product (GNP). The total market value of the goods and services produced by a nation before the deduction of depreciation charges and other allowances for capital consumption.

head (see **hydraulic head**).

heat rate. The amount of energy expressed in joules or kilocalories required to produce 1 kW·h of electric energy.

heavy water. Water containing the heavy isotope of hydrogen (deuterium). It is used as a moderator in some reactors because it slows down neutrons effectively and permits the use of natural uranium as a fuel.

heavy-water reactor (HWR). A nuclear power reactor in which heavy water is both moderator and coolant.

hertz. Unit to express electrical frequency of alternating current, representing cycles per second.

hydraulic head. The difference in hydraulic pressure between two points expressed in terms of the vertical length of a column of water which represents the same pressure; the elevation between the headwater surfaces above and the tailwater surface below a hydroelectric power plant.

(1) *Critical:* The head at which the full-gate output of the turbine equals the nameplate capacity of the generator.

(2) *Gross:* The difference in elevation between the headwater surfaces above and the tailwater surface below a hydroelectric power plant, under specified conditions.

(3) *Net:* The gross head less all hydraulic losses except those chargeable to the turbine.

(4) *Operating:* The hydraulic head existing during operation of a hydroelectric plant, often expressed as a range.

hydroelectric power plant. An ordered arrangement of engineered civil structures, machines and equipment of various kinds designed chiefly to convert the gravitational potential energy of water into mechanical and electrical energy.

identified resources. Resources whose location, grade, quality and quantity are known or estimated from specific geological evidence. Identified resources include economic, marginally economic and subeconomic components. To reflect varying degrees of geological certainty, these economic divisions can be subdivided into measured, indicated and inferred.

income elasticity. The percentage change in the quantity demanded of a product for 1% change in income.

indicated reserves. Reserves that include additional recoveries from known deposits (in excess of the measured reserves) which engineering knowledge and judgement indicate will be economically available.

indirect costs. Include the costs of construction services (e.g. temporary site facilities, tools, fuel, lubricants, permits), project management, and home and field office engineering services.

inferred reserves. Reserves in addition to measured and indicated reserves eventually to be added to known fields by extensions and revisions.

inflation. The change over time of the average prices of goods and services in the general economy.

intake works. A structure to facilitate entry of water to the conduit system; may or may not be submerged (hydroelectric power plant).

interconnection. A transmission line joining two or more power systems through which power produced by one can be used by the other.

interest during construction (IDC). The accumulated money disbursed by a utility to pay off interest on the capital invested in the plant during construction. Associated with every project are financial costs related to the use of capital. Money borrowed or committed for project implementation must eventually be paid back or recovered, with interest. A generic term in wide use is *allowance for funds used during construction* (AFUDC), which includes the IDC as well as certain brokerage fees and other expenses related to the procurement of the loans.

irradiated (nuclear) fuel. Nuclear fuel that has been exposed to irradiation in a nuclear reactor; irradiated fuel contains considerable amounts of radioactive fission products (also called **spent fuel**).

joule. Unit of work or energy, being the amount of work done by one newton acting through a distance of one metre:

$$1 \text{ joule} = 1 \text{ newton} \cdot \text{metre} = \frac{1 \text{ kg} \times \text{m}^2}{\text{s}^2}$$

kilowatt (kW). A unit of power equal to 1000 watts, or to energy consumption at a rate of 1000 joules per second.

kilowatt-hour (kW·h). The amount of electrical energy involved in a 1 kW demand over a period of one hour.

levelized energy cost. Calculated by assuming that the present worth value of all revenues produced by the electricity generated (price at the level cost of the kW·h) equals the present worth value of all expenditures incurred in the implementation and operation of the plant.

life. *(1) Economic:* that period of time after which a machine or facility should be discarded or replaced because of its excessive costs or reduced profitability; the economic impairment may be absolute or relative. (2) *Physical:* that period of time after which a machine or facility can no longer be repaired in order to perform its design function properly. (3) *Service:* the period of time that a machine or facility will satisfactorily perform its function without major overhauls.

light-water reactor (LWR). Nuclear reactor in which water is the primary coolant and moderator. There are two commercial types: the boiling-water reactor (BWR) and the pressurized-water reactor (PWR).

lignite. A brownish-black low-grade coal of a variety intermediate between peat and bituminous coal, with high inherent moisture and volatile matter. It is used almost exclusively for electric power generation.

load. The amount of power needed to be delivered at a given point on an electric system.

load curve. A curve showing loads, plotted against chronological time of occurrence and illustrating the varying magnitude of the load during the period covered.

load duration curve (LDC). A curve that portrays the percentage of time during which particular load levels occur or are exceeded.

load factor. The ratio of the average load during a designated period to the peak or maximum load occurring in that period.

load following. Load-following capability refers to the unit's ability to meet the changing (increasing or decreasing) load requirements of the system.

load management. Any means or application of measures by which load curves may be made flatter in shape, i.e. increasing system load factor.

load shedding. The process of deliberately disconnecting preselected loads from the power system in response to a loss of power input to the system in order to maintain the nominal value of the frequency.

loading order. The relative rankings assigned to units and blocks of units to be dispatched. The goal in ranking units is to provide a dispatching order that minimizes generation costs while satisfying all operating constraints.

loss of energy probability (LOEP). The ratio of the expected amount of energy curtailed owing to deficiencies in available generating capacity to the total energy required to serve the requirements of the system.

loss of load expectation (LOLE). The expected number of days (or hours) per year in which insufficient generating capacity is available to serve the daily (or hourly) peak load. LOLP is then defined as LOLE/N, where N is the number of time increments in the LOLE calculation (i.e. N = 365 if LOLE is calculated from daily peak load data and is expressed in terms of days, while N = 8760 if LOLE is calculated from hourly load data).

loss of load probability (LOLP). The proportion of time when the available generation is expected to be unable to meet the system load.

low head hydroelectric plant. Hydroelectric plant that operates with a head of about 20 m or less.

measured reserves. Mineral reserves which can be economically extracted by means of existing technology and whose amount is estimated from geological evidence supported directly by engineering measurements.

metallurgical coal. Coal with strong or moderately strong coking properties that contains no more than 8% ash and 1.25% sulphur, as mined or after conventional cleaning.

mixed years money (see **current money**).

model. In applied mathematics, an analytical or mathematical representation or quantification of a real system and the ways that phenomena occur within that system. Individual or subsystem models can be combined to give system models. Deterministic and probabilistic models are two types of mathematical model.

Monte Carlo analysis. A stochastic method of simulation analysis that involves statistical sampling techniques in obtaining a probabilistic approximation to the solution of a problem. The method requires continued sampling of values of a large number of elementary events by the application of the mathematical theory of random variables.

net capacity. Corresponds to the electric output measured at the station outlet terminals, i.e. after deducting the power taken by station auxiliaries and the losses in the transformers that are considered integral parts of the station.

net head. Equivalent to the gross head less the hydraulic losses (in metres) in the different elements conveying water to the turbine (hydroelectric power plant).

newton (N). Unit of force (F), being the force which imparts to a mass (m) of one kg an acceleration (γ) of one metre per second:

$$F = m \times \gamma \; ; \quad \text{newton} = \text{kg} \times \frac{\text{m}}{\text{s}^2}$$

nuclear fuel. Fissile and/or fertile material for use as fuel in a nuclear reactor.

nuclear fuel cycle. The steps in supplying fuel for nuclear reactors. These include mining, uranium refinement, uranium conversion, uranium enrichment, fabrication of fuel elements, their use in a nuclear reactor, chemical processing to recover remaining fissile material, re-enrichment of the fuel, fabrication into new fuel elements, and waste storage.

nuclear fuel reprocessing. The chemical processing of spent reactor fuel to recover the unused, residual fissionable materials.

nuclear power plant. A nuclear reactor or reactors together with all structures, systems and components necessary for the safe production of power, i.e. heat or electricity.

nuclear reactor. A facility in which a fission chain reaction can be initiated, maintained and controlled. Its essential component is a core with fissile fuel. It usually has a moderator, reflector, shielding, coolant and control mechanisms. It is the basic machine of nuclear power. (See **fission.**)

nuclide. A species of atom characterized by its mass number, atomic number and nuclear energy state. (See **radionuclide.**)

obsolescence. (1) The condition of being out of date; a loss of value occasioned by new developments which place the older property at a competitive disadvantage; a factor in depreciation. (2) A decrease in the value of an asset brought about by the development of new and more economical methods, processes, and/or machinery. (3) The loss of usefulness or worth of a product or facility as a result of the appearance of better and/or more economical products, methods or facilities.

off-peak. Periods of relatively low system demands.

on-peak. Periods of relatively high system demands.

operation and maintenance costs (O&M). All non-fuel costs such as the direct and indirect costs of labour and supervisory personnel, consumable supplies and equipment, outside support services, and (if applicable) moderator and coolant makeup and nuclear liability insurance. O&M costs are made up of two components: fixed costs (those that are invariant with the electrical output of the plant) and variable costs (those non-fuel costs that are incurred as a consequence of plant operation, e.g. waste disposal costs or the cost of limestone in a flue gas desulphurization system).

operation factor (OF) (%). $OF = h/H \times 100$, where h = number of hours on line and H = number of hours in the reference period. The operation factor is the ratio between the number of hours the unit or station was on line and the total number of hours in the reference period.

outage. The period in which a generating unit, transmission line or other facility is out of service.

overhead. A cost or expense inherent in performing an operation, i.e. engineering, construction, operating or manufacturing, which cannot be charged to or identified with a part of the work, product or asset and therefore must be allocated on some arbitrary basis believed to be equitable, or handled as a business expense independent of the volume of production.

overnight construction costs. Construction costs at a particular point in time, i.e. assuming instantaneous construction.

payoff period. (1) Regarding an investment, the number of years (or months) required for the related profit or saving in operating cost to equal the amount of said investment. (2) The period of time when a machine, facility or other investment has produced sufficient net revenue to recover its investment costs.

peak load. The maximum load in a stated period of time.

peaking capacity. That part of a system's capacity which is operated during the hours of highest power demand.

penstock. Pressure pipe for conveying water from the forebay to the turbine (hydroelectric power plant).

petroleum. Literally 'rock oil', a naturally occurring flammable liquid consisting mainly – usually more than 90% – of a complex mixture of hydrocarbons; it is commonly called crude oil or, simply, crude. Several hundred different hydrocarbons, with up to at least 60 carbon atoms per molecule, are present in petroleum. Petroleum refining leads to the production of important fuels: diesel fuel, fuel oil, jet fuel, gasoline, kerosine and liquefied petroleum gas. Petroleum is also the source of many chemical products called petrochemicals.

plutonium. A fissionable element that does not occur in nature but is obtained by exposure of ^{238}U to neutrons in a reactor.

power. The rate of energy that can be generated by a power plant or consumed by an electric system (measured in kW). In a hydroelectric plant the power generated is proportional to the product of the net head and the water flow.

power distribution (see **power transmission**).

power factor. The ratio of the amount of power, measured in kW, used by a consuming electric facility to the apparent power measured in kV·A.

powerhouse. Structure in which the generators and other electro-mechanical equipment are housed (hydroelectric power plant).

power transmission. In the electric utility industry, transmission refers to the transport of large blocks of power over considerable distances (1) from a central generating station to main substations close to major load (or consumption) centres or (2) from one central station (or power system) to another for load sharing. Distribution is the subsequent transport of smaller blocks of power to individual users.

present value (present worth). Present valuing is a mathematical process by which different monetary amounts can be moved either forward or backward from one or more points in time to a single point in time, taking account of the 'time value of money' during interim periods.

pressurized-water reactor (PWR). A power reactor in which heat is transformed from the nuclear fuel core to a heat exchanger by water kept under high pressure to prevent it from boiling. Steam is generated in a secondary circuit which can fuel a turbine for electricity generation.

price elasticity. The percentage change in the quantity demanded of a product for 1% change in the price of that product.

primary energy. Energy in its naturally occurring form (coal, oil, uranium) before conversion to end-use forms.

probability. A basic concept which may be taken either as undefinable, expressing in some way a degree of belief, or as the limiting frequency in an infinite random series. Both approaches have their difficulties and the most convenient axiomization of probability theory is a matter of personal taste. Fortunately both lead to much the same calculus of probabilities.

probability distribution. A distribution giving the probability of joint occurrence of a set of variables $x_1 \ldots x_p$ as a function of those quantities. It is customary, but not the universal practice, to use 'probability distribution' to denote the probability density (of a discontinuous or continuous variate, respectively) and some such expression as 'cumulative probability distribution' to denote the probability of values up to and including the argument x. From a frequency viewpoint the distinction is the same as between frequency function and distribution function.

pumped storage. The operation whereby water is raised during off-peak periods by means of pumps and stored for later use in the production of electricity during peak load periods.

radioactivity. The property of certain nuclides of spontaneously emitting particles or gamma radiation, or of emitting X-radiation following orbital electron capture, or of undergoing spontaneous fission.

radionuclide. A radioactive nuclide.

rate of return on investment. The interest rate at which the present worth of annual benefits equals the present worth of annual costs.

real escalation, differential escalation or **cost drift.** The annual rate of price increase that is independent of and over and above inflation. This can result from resource depletion, increased demand, technology evolution, safety and environmental requirements, etc.

recycling. The reuse of nuclear fuel material after it has been recovered by chemical processing from spent or depleted reactor fuel.

reprocessing of spent fuel. Chemical recovery of unburned uranium and plutonium and certain fission products from spent nuclear fuel elements.

reserve margin (RM). A measure of the generating capacity that is available over and above the amount required to meet the system load requirements.

reserves. That part of the resources known to be recoverable with current technology under present economic conditions.

(1) *measured reserves.* Identified resources from which an energy commodity can be economically extracted with existing technology, and whose location, quality and quantity are known from geological evidence supported by engineering evidence.

(2) *indicated reserves.* Reserves based partly on specific measurements, samples or production data and partly on projections for a reasonable distance on geological data.

(3) *inferred reserves.* Reserves based on broad geological knowledge for which quantitative measurements are not available. Such reserves are estimated to be recoverable in the future as a result of extensions, revisions of estimates, and deeper drilling in known fields.

residual fuel oil. A heavy fraction from the distillation of crude oil, often used as a fuel for power plants.

resources. Concentrations of naturally occurring solid, liquid or gaseous material in or on the Earth's crust in such form that economic extraction of a commodity is currently or potentially feasible.

run-of-river plant. A hydroelectric power plant using the flow of a stream as it occurs and having little or no reservoir capacity for storage.

salvage value. The market value of a machine or facility at any point in time. Normally, an estimate of an asset's net market value at the end of its estimated life.

scheduled outage. The scheduled or planned shutdown of a generating unit, transmission line or other facility for inspection, preventive maintenance or repair.

sensitivity analysis. An analysis of the effect on the solution of a mathematical problem, for example, as the parameters of the problem are varied.

separative work unit (SWU). The measure of work required to produce enriched uranium from natural uranium. Enrichment plants separate natural uranium feed material into two groups, an enriched product group with a higher percentage of ^{235}U than the feed material and a depleted tails group with a lower percentage of ^{235}U than the feed material. To produce 1 kg of enriched uranium containing 2.8% ^{235}U and a depleted tails assay containing 0.3% ^{235}U requires 6 kg of natural uranium feed and 3 SWU.

silt basin. A system for preventing solid particles from entering the penstock (to protect the turbines). May be installed as part of the intake works or the forebay, depending on flow, terrain and material of which the channel is constructed. (Hydroelectric power plant.)

simulation analysis. A general method of studying the behaviour of a real system or phenomenon. The method usually involves devising a model representing the essential features of the system and carrying out the solution of the mathematical and logical relations of the model. The simulation can be either deterministic or stochastic depending on the model selected. Markov chain analysis and Monte Carlo analysis are two well-known examples of stochastic simulation techniques.

sinking fund. (1) A fund accumulated by periodic deposits and reserved exclusively for a specific purpose, such as retirement of a debt or replacement of a property. (2) A fund created by making periodic deposits (usually equal) at compound interest in order to accumulate a given sum at a given future time for some specific purpose.

site preparation. An act involving grading, landscaping, installation of roads and siding, of an area of ground upon which anything previously located has been cleared so as to make the area free of obstructions, entanglements, or possible collisions with the positioning or placing of anything new or planned.

speed regulator *or* **governor.** A servo-mechanism which keeps the turbine revolving at a constant speed and consequently maintains a constant electrical frequency.

spent fuel. Nuclear reactor fuel elements that have been irradiated in a reactor and have been utilized to an extent such that their further use is no longer efficient.

spinning reserve. The generating capacity that can be called on in a few seconds to supply power in the event of sudden load increases or unit failures. It is equal to the total amount of generation available from all units synchronized (i.e. spinning) on the system minus the present load plus losses being supplied.

startup costs. Extra operating costs to bring the plant on stream incurred between the completion of construction and beginning of normal operations. In addition to the difference between actual operating costs during that period and normal costs, it includes employee training, equipment tests, process adjustments, salaries and travel expenses of temporary labour staff, as well as consultants, report writing, post-startup monitoring, and associated overheads. Additional capital required to correct plant problems may be included. Startup costs are sometimes capitalized.

stochastic analysis. Decomposition of a time series into deterministic and probabilistic components.

stochastic event. A random event which can be predicted only by the probability of its occurrence. The term applies to data on phenomena that occur in time and/or space which are basically of a probabilistic nature but whose values depend partially on their respective time and/or space co-ordinates. In a stochastic time series, a term in the series is significantly related to the next one and this is considered in the time series analysis and synthesis.

straight-line depreciation. Method of depreciation whereby the amount to be recovered (written off) is spread uniformly over the estimated life of the asset in terms of time periods or units of output.

sum-of-digits method. Also known as sum-of-the-years-digits method. A method of computing depreciation in which the amount for any year is based on the ratio: (years of remaining life)/(1 + 2 + 3...+n), n being the total anticipated life.

surge tank. A structure for compensating overpressure in the penstocks (hydroelectric power plant).

surplus power *or* **secondary power.** All available power in excess of the firm power (hydroelectric power plant).

synthetic natural gas (SNG). A gaseous fuel manufactured from naphtha or coal which has an energy content about that of natural gas.

tail race. Structure which carries water from the powerhouse either to downstream of the river from which it was taken or to a neighbouring basin (hydroelectric power plant).

thermal efficiency. As applied to a heat engine, the proportion of the heat taken up that is converted into useful work, i.e.

$$\text{thermal efficiency} = \frac{\text{heat converted into useful work}}{\text{heat taken up}}$$

In electric power generation, the useful work done (or heat converted into useful work) is taken to be the electrical energy generated in a certain time; the thermal efficiency is then defined by:

$$\text{thermal efficiency} = \frac{\text{electrical energy generated}}{\text{heat produced by fuel consumed}}$$

where electrical energy and heat produced are expressed in the same energy units (e.g. kW·h, J, etc.). The heat produced is based on the fuel, fossil or nuclear, consumed for the period over which the energy is generated. In an electric power generation plant, a distinction is made between the gross and net thermal efficiencies. The gross efficiency is based on the total electrical energy (or power) generated. The net efficiency, on the other hand, is based on the energy (or power) available for sale. The difference represents the power required to operate the plant and associated equipment.

thermal power plant. Any electric power plant that operates by generating heat and converting the heat to electricity.

time value of money. The effect of time on the value of money.

total capital investment costs (TCIC). The total costs incurred throughout the project schedule including escalation and interest charges up to commercial operation of the power generation facility.

transformer. An electromagnetic device for changing the voltage of alternating current electricity.

transmission line. System used to transmit the electrical energy from the power plant to the point of consumption.

turbine. A hydraulic motor that converts the energy of the water into mechanical energy (hydroelectric power plant).
Pelton. A free-jet impulse turbine used for high heads; low cost.
Michel-Banki. Cross-flow impulse turbine used for medium heads; low cost, low efficiency.
Francis. Reaction turbine (operates filled with water) used for medium heads; high cost, high efficiency.
Axial. Reaction turbine (variants: with adjustable blades (Kaplan); fixed blade propeller-type; tubular-type; bulb-type) used for low heads. (Axial units and Francis units operate filled with water.)

turbine plant equipment. The turbo-generator set and all the associated ancillary equipment such as condensing equipment, feedwater heating system, chemical treatment facilities (thermal power plant).

unavailability. When the available capacity is lower than the maximum capacity.

unavailability factor (UF) (%). UF = E_u/E_m. The unavailability factor over a specified period is the ratio of the energy E_u that could have been produced during this period by a capacity equal to the unavailable capacity C and the energy E_m that could have been produced during the same period by the maximum capacity. For a nuclear power plant the unavailability factor UF over a specified period can be divided into:

PUF: unavailability factor owing to planned outages, such as refuelling and maintenance work, and

UUF: unavailability factor for all other reasons.

undiscovered resources. Resources, the existence of which is only postulated, comprising deposits that are separate from identified resources. Undiscovered resources may be postulated in deposits of such grade and physical location as to render them economic, marginally economic or subeconomic.

uranium, natural. A radioactive element with the atomic number 92 and an average atomic weight of about 238. The two principal isotopes are ^{235}U (0.7% of natural uranium), which is fissile (capable of being split and thereby releasing energy) and ^{238}U (99.3% of natural uranium), which is fertile (having the property of being convertible to fissile material).

uranium conversion. The chemical processing of uranium concentrates into uranium hexafluoride. (See **nuclear fuel cycle.**)

uranium enrichment. A process by which the proportion of fissile uranium isotope (^{235}U) is increased above the 0.7% contained in natural uranium. (See **nuclear fuel cycle.**)

useful energy. The actual energy used by the consumer to perform a useful function (e.g. provide heat, motive power, lighting, etc.). It represents the energy output of a conversion device (e.g. boiler, furnace, water heater); it differs from the energy consumption by the efficiency of the conversion device.

variable costs. Raw materials costs, by-product credits, and those processing costs which vary with plant output (such as utilities, catalysts and chemicals, packaging, and labour for batch operations).

waste management. All activities, administrative and operational, involved in the handling, treatment, conditioning, transport, storage and disposal of waste.

water flow. Quantity of water (volume) per unit of time, in m^3/s (hydroelectric power plant).

watt (W). The rate of energy transfer equivalent to one ampère under an electrical voltage of one volt. One watt equals one joule per second.

watt-hour (W·h). The total amount of energy used in one hour by a device that uses one watt of power for continuous operation.

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