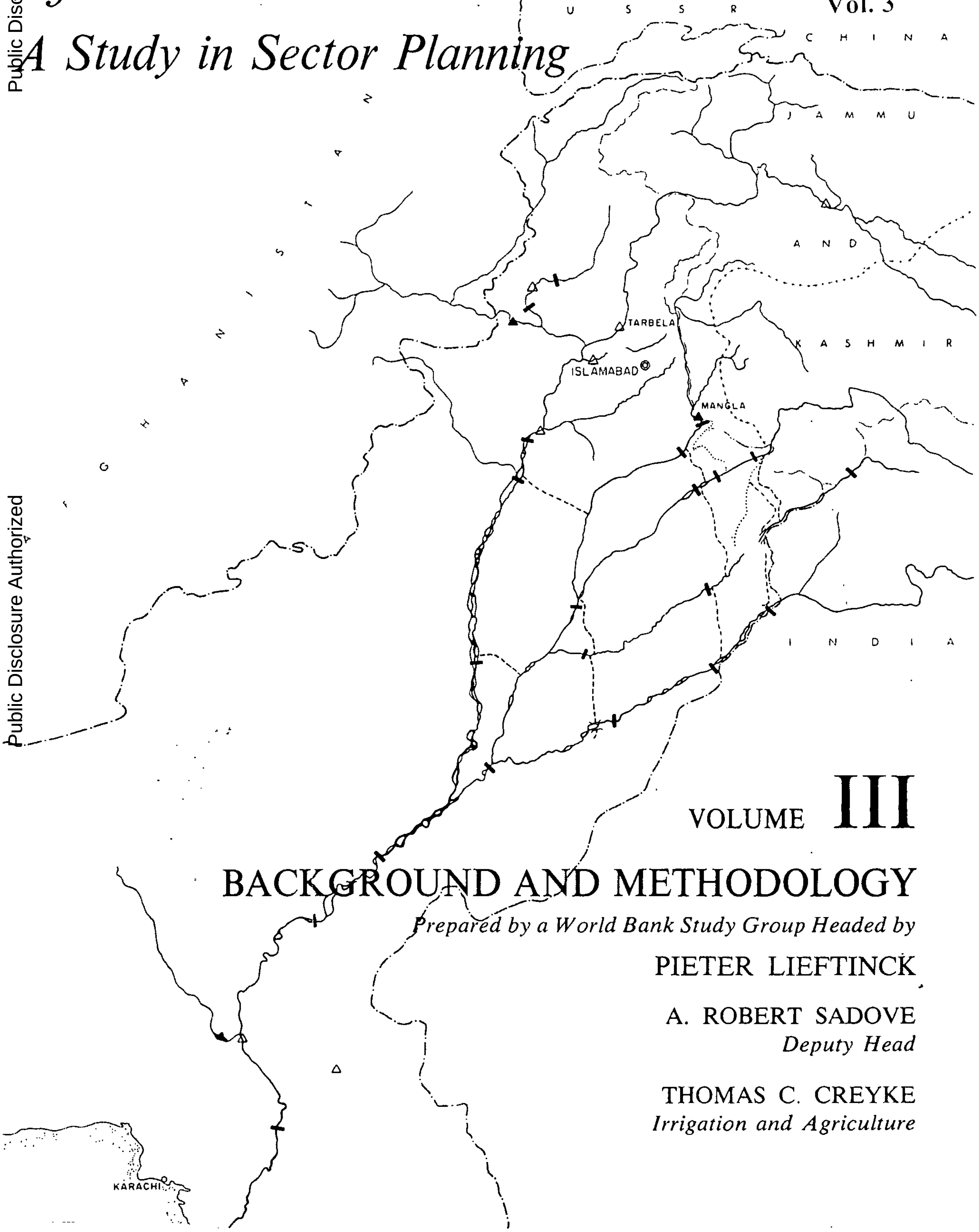
Water and Power Resources of WEST PAKISTAN

A Study in Sector Planning



VOLUME III

BACKGROUND AND METHODOLOGY

Prepared by a World Bank Study Group Headed by

PIETER LIEFTINCK

A. ROBERT SADOVE
Deputy Head

THOMAS C. CREYKE
Irrigation and Agriculture

WATER AND POWER RESOURCES OF WEST PAKISTAN

A Study in Sector Planning

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Prepared by a World Bank Study Group Headed by Pieter Lieftinck; A. Robert Sadove, Deputy Head; Thomas C. Creyke, Irrigation and Agriculture.

Without doubt, the greatest single co-ordinated development operation in which the World Bank has been involved is the massive program for development of the Indus Basin. This pioneering study is an integral part of that project and is unique both in its conceptualization and its comprehensiveness. It demonstrates the feasibility of a new and more rigorous approach to resource planning and development and will serve as an indispensible model for engineers, economists, and planners for years to come.

Focal points of the Study are the Indus River, which runs the length of West Pakistan, several of its tributaries, and a huge natural underground reservoir. In developing a realistic investment program for water and power, the Bank's Study Group had to consider a host of interrelated factors: the objective of maximizing economic returns, the competition for scarce resources, all aspects of agricultural production, alternate sources of water for irrigation, the country's projected electricity requirements, and the coordination of decisions regarding power generation and agriculture.

VOLUME III

Water and Power Resources of West Pakistan
A Study in Sector Planning

BACKGROUND AND METHODOLOGY
SUPPLEMENTAL PAPERS

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PIETER LIEFTINCK

A. ROBERT SADOVE
Deputy Head

THOMAS C. CREYKE
Irrigation and Agriculture

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The Bank Study Group

Head of Study
PIETER LIEFTINCK

Deputy Head of Study
A. ROBERT SADOVE

Chief, Irrigation and Agricultural Studies
THOMAS C. CREYKE

Agricultural Economics
WILLI WAPENHANS
JAMES B. HENDRY
HAROLD MANNING
KYAW MYINT

Dam Site Engineering
GENERAL HERBERT D. VOGEL

Power
A. D. SPOTTSWOOD
CHRISTOPHER WILLOUGHBY

Engineering Consultants
E. P. DELANY
K. B. NORRIS

General Economics
HEINZ VERGIN

General Assistance
FIROUZ AFROUZ
STANLEY P. JOHNSON
GARY S. LUHMAN
HUDA QUBEIN

Editorial Assistance
THOMAS B. WINSTON

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VOLUME III

Water and Power Resources of West Pakistan
A Study in Sector Planning

BACKGROUND AND METHODOLOGY
SUPPLEMENTAL PAPERS

General Introduction

This Volume presents nine supplemental papers on the background and methodology used in the Indus Study. The papers cover a variety of topics but broadly they can be grouped into three sections. The groupings are necessarily somewhat arbitrary because of the many crosscurrents running through the subject matter of the Study. The first three papers are devoted to the economic framework within which the Indus Study was carried out; they cover such matters as the structure and growth of the economy, population growth, foreign exchange parities, the power load forecast and the economic valuation of fuel resources. This first section provides a bridge, so to speak, between the programs proposed in Volumes One and Two, and Pakistan's macroeconomic planning. The second grouping, Supplemental Papers No. 4 and 5, is devoted to testing the economic efficiency of the irrigation and agriculture program: a linear program of irrigation development in the Basin, and the economics of private tubewell electrification. A third group of papers is devoted to power system problems: the pattern of reservoir operation, the power benefits of the multipurpose Tarbela Dam Project, interconnection of power networks, and the nature and scope of the simulation model used in testing the behavior of proposed projects over time.

There are separate introductions to each part. As far as possible, these introductions are subdivided in terms of functional problems rather than the subject matter of each Supplemental Paper. Thus, Papers are sometimes discussed out of order—for instance, Supplemental Papers No. 6 and 7 find themselves in companionship with Supplemental Papers No. 3 and 4 in their relationship to multisectoral links. The Papers also appear more than once in various contexts. It is hoped that this device will help to chart the crosscurrents and to clarify the nature of the problems and procedures.

These nine papers were selected from among a great variety of reports and studies prepared in the course of this Study. The Study Group believes they will serve a double purpose: to illuminate the conclusions and recommendations in Volume One and Two, and to illustrate some of the technical complexities of carrying out the Study—for the benefit of development authorities, who increasingly in today's world must be able to discuss such matters, and for the interest of professional practitioners engaged in this kind of work. Many of the methodological problems encountered, many of the ongoing issues and controversies (and there were many) have long since been buried in the massive files accumulated by the Study Group and its consultants over the nearly four years this Study was in progress. This Volume, however, should demonstrate what the Study Group believes has been a rather ambitious effort to open up new paths to effective sector planning, to bridge the gap between the traditional project approach and macroeconomics.

The methodology, as formulated by the Study Group and agreed with the Government of Pakistan, stressed the comprehensive nature of the task. The review of power development would cover all aspects of the available resources, including water power, the energy of gas, oil and coal, and the potential of nuclear power. The general review of water development would cover all of the main factors—land use, manpower, groundwater and surface water, crop yields, etc.—governing agricultural production, particularly but not exclusively irrigated crop production. The development potentials of the various regions of the Indus Basin were to be studied, with an effort made to identify the steps needed to realize their potentials. However, specific project proposals for water and power development were to be the end product of the Study. Projects were to be studied within a Basinwide context, within the framework of development planning in West Pakistan. Thus, projects had to be fully integrated into a program phased over time. In fact, the time dimensions were taken as those of Pakistan's Five Year Plans—the Third Plan is currently being implemented (1965–70). Because development planning has reached an advanced stage in Pakistan, the underlying analytical procedures and arguments could be related to the overall economic framework as given and the programs could be related to national economic objectives. It was agreed that the final document would not be binding on anyone: the Study Group's findings would be a contribution to ongoing debate—hopefully a persuasive contribution—rather than a fait accompli.

The links between projects and sector plans were, from the outset, in the forefront of the Study Group's attention. As the Study got under way, the working premise was that fitting projects into a realistic sector plan would be the major task of the Study Group. It was believed that, once data were collected, selecting projects for irrigation development would be mainly a matter of reviewing the priority status and technical aspects of projects already formulated by the Pakistan Authorities. "Ongoing projects," defined as projects for which finance had been committed or was being negotiated, were to be accepted as given: by an agreement with the Pakistan Government, they were outside the purview of the Study. But in the course of the Study, it became apparent that—apart from Tarbela and one large drainage scheme—there were virtually no water development projects prepared and formulated that were not already ongoing. As a result, the scope of the Study Group's consultants' assignment had to be broadened to include, in addition to review of existing project proposals, the identification and tentative formulation of new projects. To accomplish this objective, it was decided that the consultants would have to assign about three-quarters of their strength to project work. Likewise, at a later stage, increased emphasis had to be placed on project evaluation in the work of the Study Group. And in turn, this concern with project detail reinforced the Study Group's desire—now a necessity—to explore pragmatic means of linking the conventional project approach with sophisticated computer programming methods.

The so-called Action Program has been formulated through a series of approximations, some based on specific projects, some on broad regions of development and some on general farming requirements for fertilizers, seeds, etc. In some cases, crude "hand" methods of evaluation were employed, particularly for preliminary comparisons of various possible means of irrigation development. However, underlying the final testing of the program were basic analyses which combined detailed studies of the way in which agriculture is carried out with computer simulations of the water and power systems of West Pakistan. These tests, while "hypothetical," were designed to simulate a reality that would be consistent with what was actually known about the implementation capacities and the availability and usage of surface water and groundwater. Project priorities were finally established on the basis of the formal analyses growing out of these simulations, with some relatively minor "hand" adjustments in light of practical considerations and vagaries which could not be incorporated into the mathematical comparisons. The end result was an integrated, phased development program. Surface water storage projects were combined with other forms of developments to meet the water requirements projected in the simulation analyses. The economic efficiencies of the individual components were also again tested both by a series of project benefit-cost calculations and by an overall appraisal based on a linear programming exercise.

The use of operational research techniques was particularly fruitful in the case of West Pakistan. WAPDA, the water and power agency, had already embarked on the development of a simulation model of the Indus Basin hydrological system, through its general consultant, Harza Engineering Company of Chicago, and therefore it was possible, even though time was short, to test the technical integration and behavior of the proposed program on a sequential model. Similarly, the Pakistan Planning Commission and its consultants have been working on a number of macroeconomic models, some of which provided very useful tools that were adequate for testing the consistency of the proposed programs with the country's Five Year Plans.

The names of the Bank's consultants appear from time to time in these papers. For the irrigation and agricultural aspects of the Study, three firms formed, for this purpose, an Irrigation and Agricultural Consultants Association (IACA); the member firms were Sir Alexander Gibb & Partners and Hunting Technical Services Limited, both of the U.K., and International Land Development Consultants (ILACO) of the Netherlands. To handle questions concerning dam sites, Chas. T. Main International, Inc., a U.S. firm, was retained; for power, Stone & Webster Overseas Consultants, Inc., also from the United States. In addition to their role in IACA, Sir Alexander Gibb & Partners were responsible for overall coordination among the consultants. Two individual consultants gave assistance to the Study Group on methodological problems. Dr. Henry D. Jacoby, of the Harvard Water Program, prepared a simulation model of West Pakistan's power system. Professor Robert Dorfman, also of Harvard University, gave direction to the linear programming analysis of investment in irrigation and agriculture. A full list of contributors to the Study is contained in the Foreword, Volume One. The members of the Study Group have been indicated at the beginning of this Volume.

BACKGROUND

Most readers of this Volume will no doubt be familiar with the background of the Study, as well as the main lines of argument and the conclusions, from Volume One or both of the preceding Volumes. But, since this is a separate Volume dedicated mostly to particular technical matters, some readers may desire a brief resume, in very broad terms, of some basic facts, events and considerations involved in the Study Group's report. This very brief review by no means should be regarded as a summary of findings.

This Special Study was derived from the Indus Waters Treaty of 1960, which called for diverting the flow of three tributaries to India's use. The Study's chief purpose was to develop a program for the optimum exploitation, for agricultural and power purposes, of the water resources that would be available to Pakistan after implementation of the Treaty. A first objective was the completion of a report covering the technical feasibility, construction cost, and economic return of a dam on the Indus at Tarbela. A report was issued on February 15, 1965 which reached the conclusion that the Tarbela Project is technically and economically feasible. This favorable verdict set the stage for the comprehensive Basinwide study of water and power resources reported on in these Volumes. Reevaluated in the broader context, Tarbela again proved itself the most favorable project for first stage storage on the Indus. Estimated to cost about $900 million, the Tarbela Project can be regarded as the centerpiece of the proposed development program; it also provides a focal point, in that the Study Group concluded that the project should be completed as planned by 1975. Three-fourths of Tarbela's benefits and costs are assigned to agriculture, the other fourth to power. The closest competitor to Tarbela was a dam at Kalabagh, on a site over 100 miles downstream.[1]

Following full implementation of the Indus Waters Treaty, the surface water available to West Pakistan in a mean-flow year will be some 142 MAF. There is also an extensive groundwater aquifer. An estimated 14 million acres of the canal-irrigated area lies over groundwater of sufficient quality to be used directly for irrigation, and another five million acres have groundwater that can be used for irrigation after mixing with surface water. The uppermost 100 feet of the usable groundwater aquifer in the irrigated areas contain about 300 MAF of usable water.

Proposed water development strategy is predicated on an integrated use of surface water and groundwater resources, availability of the cheaper source; groundwater, when pumped on the basis of balanced recharge of the aquifer, was given first consideration. Canal enlargement provides another possible means of increasing supplies; but partly for technical reasons, the other sources form the major elements of the proposed program. Private tubewells have increased rapidly in recent years; the Study Group recommended policies conducive to a continuation of this rapid growth. A large public tubewell program is also recommended for areas (a) where there are good opportunities for groundwater development but the private sector is less enterprising and (b) where the problem of waterlogging and salinity needs to be immediately controlled. All these modes of development, in addition to drainage projects, are to some degree interdependent; none can be adopted alone without eventually creating the need to embark on one or more of the others. In addition, each is subject to administrative and technical constraints which limit the speed with which it can be pursued.

Proposed public sector expenditures on agricultural nonwater inputs represent the largest single bloc in the program. Water requirements are based on a concept

[1] It should be noted that the Mangla Multipurpose Project on the Jhelum, completed in 1967, was "ongoing" during the course of this Study. For the first time, it gave West Pakistan control over a sizeable proportion of the total flows of a major river.

taken to be the full amount needed to support modern agricultural techniques. This means better irrigation farming practices and more physical inputs such as fertilizers, improved seed and plant protection. It also means a drastic improvement in institutional arrangements including research, agricultural credit, and extension service—the critical link in getting innovations to the stage of actual adoption and showing farmers how to make best use of new inputs. The Study Group emphasized that, although the Tarbela reservoir plus tubewells will provide an adequate water base, the development of irrigated farming cannot realize its potential fully without the simultaneous use of improved seeds and fertilizers, the adoption of new cropping patterns and better techniques of husbandry.

A major conclusion is that the proposed programs would allow a growth of about 4.5 percent per year in agricultural output for the decade 1965–75 and this would be consistent with a growth of nearly 6 percent in total provincial output. Such a growth might also be consistent with food self-sufficiency and some balance of payments improvement. As regards power, the Study Group believes that a 6 percent annual growth in total output implies a need for about 13 percent annual growth in generation of electricity by public utilities over the next decade. Proposals to meet this forecast demand account for about 28 percent of the program.

There are four main features to the power program. First is the Tarbela Dam; part of its 2,100 mw of hydroelectric potential would be available by 1975. The second important component would be the completion of a 380-kv transmission interconnection starting with the Northern Grid and Mari (see Map 3) in 1971 and embracing all main load centers by the time that Tarbela comes on line. Third, and closely linked with the transmission recommendations, is a heavy concentration of thermal development near the gas fields in the Upper Sind area to provide all the main load centers in the Province with the advantage of thermal power based on cheap fuel. The fourth important feature is a continuation of thermal development based on Sui gas at the major load centers. The program proposed has been tested and examined with the aid of the computer model which the Study Group used to simulate the operation of the West Pakistan power system.

PART ONE

Macroeconomic Framework, Forecasting and Economic Pricing

Introduction

Linking the Program to the Economic Framework

The objectives of the macroeconomic analyses described in Supplemental Paper No. 1 were in line with the Terms of Reference of the Special Study, one provision being "to provide the Government of Pakistan with a basis for development planning in the water and power sectors of the economy within the context of their successive Five Year Plans. . .". Thus, the relationship of the project content of the programs to overall planning assumptions and targets had to be made explicit. The significance to the Province's economic development, both in the program's financial requirements and its expected achievements, had to be stated in the macroeconomic terms used by Pakistan's planners.

Planning documents made available to the Study Group provided an indication of the overall financial and economic framework of the development effort, including specific financial and physical targets, Government allocations of development expenditures, and the general policies which either were being or would be followed to promote economic growth. However, because most of the projections related to Pakistan as a whole, there was no specific framework for the Province of West Pakistan. The Planning Commission was working on a quantitative regional breakdown of the Perspective Plan, but the work was far from complete when this Study was undertaken. With informal guidance from the Planning Commission, however, the Perspective Plan was related to some provincial magnitudes such as projections of industrial output, exports, population, demand for agricultural commodities, etc. For more detailed projections of some other aspects of economic growth, a model was constructed (described in Supplemental Paper No. 1) to illustrate the Study Group's understanding of how the Perspective Plan could apply to West Pakistan. It is not an official version. A number of adjustments to working assumptions were felt to be desirable; as a result, some key elements are not completely consistent with documents existing for the Third Plan—e.g., a higher capital-output ratio for agriculture was adopted for the Study Group's model to be consistent with the analyses of Volume Two. In general, this model exercise confirmed the importance of several economic connections that are already emphasized in Pakistan Planning—e.g., the importance of agriculture to achieving a high growth of Gross Provincial Product (GPP), and the importance of a high marginal savings rate to achieving the target growth rate.

The model used in this macroeconomic projection for the Province was very similar to one used by the Pakistan Planning Commission in preparing their Third Five Year Plan. The model, of the linear intersectoral type, essentially relates macroeconomic magnitudes such as the overall growth rate and the savings rate to a sectoral growth pattern; the econometrics of the model balance the supply and demand relationships between sectors. At the Province level, a surplus or deficit between projected savings and investment produces an automatic adjustment in the form of import substitution. Thus, the model shows the value of import substitutes which must be produced domestically, in the year projected, if the assumed savings level is to be attained. This model was particularly useful in showing, albeit in a very *gross* fashion, the implications of the agricultural growth rate and potential import savings and exports which had been projected by the Study Group. For example, the model shows that a growth of agricultural output at 4.5 percent per year between 1965 and 1975, as projected by the Study Group, would be consistent with a growth rate in GPP of nearly 6 percent and could provide for self-sufficiency in the major agricultural products—provided a marginal savings rate of about 24 percent is achieved over this period. These relationships are discussed at some length in Supplemental Paper No. 1 because they are not entirely consistent with the Perspective Plan which assumes that a somewhat higher growth rate for agriculture will be necessary if the 6 percent target growth in GPP is to be obtained.

Multisectoral Links

Accounting for some of the more complex problems encountered in the Study, there are many points of overlap and interdependence not only within each sector but also between the power and irrigation sectors. In this respect a basic problem was to ensure consistency, both in the analyses and in the end programs. The Study Group devoted a considerable effort to this matter. As one example, the total power load forecast had to be kept in alignment with proposals for agricultural development. This alignment was largely accomplished via the maintenance of three specific sectoral forecasts: one for the tubewell pumping load (including its monthly distribution) taking cognizance of changes in proposals for public and private wells; one for rural electrification, taking cognizance of new distribution lines for the extensive public tubewell fields under consideration; and one for the industrial load, taking cognizance of requirements for manufacture of agricultural inputs such as fertilizer and for processing of agricultural output. These problems of load forecasting are discussed in Supplemental Paper No. 2. The availability of fuel was another matter that cut across the economy. Large amounts of natural gas would most certainly be required to produce more fertilizer for the farmer. Thus, the greater the fertilizer component of the proposed agricultural development program, the greater the natural gas requirements for this industry. With natural gas being a scarce resource, there would be less for power generation: the less available, the higher would be its scarcity value. The economic valuation of fuel is discussed in Supplemental Paper No. 3. These and a number of other factors greatly affected all project analyses. The evaluation of the Tarbela Dam was complicated by its being a multipurpose project—the project is justified on the basis of the sum of its agricultural and its power benefits. Thus, there was a need for reasonable precision in regard to both power and agriculture benefits. Moreover, operational policies in regard to the Tarbela Reservoir (Supplemental Paper No. 7) present conflicting options, for example, one which favors agricultural benefits—by drawing down to a low minimum level—or one which favors power benefits by the opposite decision. Reservoir operations are discussed in Supplemental Paper No. 6. With such large multipurpose storage dams, it is further possible, by changing the monthly release patterns, to favor either power or agriculture. With storage accomplished during the summer monsoon season (kharif), the reservoir can be drawn down fully to the minimum level early in the winter—releasing all the stored water for irrigation use in early rabi; or as an alternative, some water can be retained in the reservoir till late in the winter to increase hydroelectric capability in the season when power supplies will be short. To the extent that the reservoirs are drawn down early, there might be a greater requirement for thermal plant—and this would have to be largely based on natural gas, especially up to 1980. Thus, even reservoir operational policy becomes involved in the valuation of fuel resources and in turn, in the macroeconomic assumptions. As evidenced by these cross-currents, the evaluation of projects and Tarbela in particular required the most careful analysis of multisectoral links.

In addition to the linkages that were particularly apparent between agriculture and power, it was recognized that the sectors would not only be in competition with each other, they would also be in competition with other sectors for the same scarce resources. The case of natural gas exhibits the existence of this competition. But it was impossible to trace competition for all factors throughout the economy without becoming directly involved in the detailed analysis of the plans of other sectors. However, as a minimum measure to take such competition into account, the Study Group used opportunity cost for critical factors and, furthermore, in the tests of the program's economic efficiency, examined the sensitivity of the results to changes in scarcity prices for example in foreign exchange values, the cost of capital, and the marginal value of water for irrigation and power.

The Role of the Long-Term Perspective

The macroeconomic assumptions made for general planning purposes emphasized the Five Year Plans within a 20-year perspective. Such a long-term basis was also in many instances the minimum time span relevant for the formulation of intrasectoral alternatives. For example, in the power sector, there are three main primary sources of generation which, as far as can now be foreseen, may be relevant for West Pakistan over the next 20 to 30 years: hydroelectric schemes, gas-fired thermal equipment and nuclear plant. Each had to be carefully compared to reach a reasonable version of the "cheapest alternative" power program. Because the comparisons were made in terms of scarcity values, the time element considered in the analysis had to extend far enough into the future to cover adequately the interests of each of the relevant factors. Scarcity values, in other words, might have to be changed for different segments of a power program over time. As regards foreign exchange, for example, the current scarcity value of foreign exchange was set in the neighborhood of twice the current official exchange rate. But would foreign exchange become more or less scarce over time? The outlook suggested by the Perspective Plan indicates little change in the general value of foreign exchange to the economy; but the discussion in Supplemental Paper No. 3 suggests that the foreign exchange stringency may become more acute in the energy sector. As regards natural gas, in addition to long-term trends in Pakistan, some view also had to be taken as to long-term trends in fuel prices in the world at large. For instance, the future cost of liquid fuel was relevant in pricing displacement fuels for natural gas; the export market for fertilizer was relevant to production targets; technological developments in the power industry could change even basic considerations. If nuclear power or liquid fuel were to become cheap, say, in 20 years' time, and if the foreign exchange that Pakistan would have to set aside to import them would not curtail too seriously the import of other needed commodities, then it would matter little if most of the Province's gas reserves were to be used up in the meantime. Thus, a long-term view of the overall energy situation was as essential as a long-term view of the demand for electric power in the evaluation of projects in the Study; and both outlooks had to be adopted within the framework of the overall pattern of the economic growth to be expected in the Province.

One point perhaps needs emphasis: the impact of a long-term perspective can be felt over the short-term, particularly with regard to investments. For example, once it was concluded that Tarbela was justified, and that it should be completed about 1975, the phasing of other investments was immediately affected. The completion date for Tarbela is intimately allied with the justification of the 380-kv transmission system, and the conclusion that it is worth being brought in, especially some part of it, prior to 1975. The long-term phasing of the comprehensive program also affected proposed developments in the next five to 10 years as to the types and location of tubewells that should be installed, the location of thermal electric equipment, the types of fuel that should be used for thermal generation, and the types of facilities that should be built to supply gas. The long-term perspective is seen to be vital throughout the many discussions of technical issues in these Supplemental Papers.

Many issues also depend on the accuracy of the various long-term projections. In evaluating and refining the electric load forecasts, for example, the Study Group attempted to develop meaningful relationships between the growth of electricity consumption and specific measures of economic activity. This was to be difficult by the fact that projections of the basic economic variables, such as national income, industrial output, and growth of urban areas were not readily available, and there was doubt as to the statistical reliability of some data that were available. Settling on what macroeconomic estimates to use was a troublesome aspect of the Study Group's work from the outset. Power projections in particular depended on reconciling forecasts derived from various economic factors. Similarly, because of conflicting data, the Study Group took particular care in settling on population estimates (see the Annex to Supplemental Paper No. 1).

The importance of both the accuracy of the projections and their time perspective to the Study also can be illustrated by the relationship of the load forecast to the power aspects of the Tarbela Project. The physical fact that Tarbela will take some eight or nine years to build means that the earliest load of relevance is that of 1975. Moreover, since in all probability Tarbela's initial capacity will more than meet the available load at that time, the growth of power demand in the years after 1975 will be critically important in determining how quickly additional power units at the dam should be installed and hence how quickly the full power benefits can be realized. Also, the Provincial power load as a whole becomes relevant only as the power markets become interconnected; hence, the geographical pattern of load growth is important to the Study of the power benefits attaching to Tarbela: e.g., the scheduling of the power units cannot be studied in isolation from power transmission. And, because a considerable part of the benefit of EHV transmission will arise in later years, after 1985, the load forecast must look at least 20 years into the future and must include considerable detail on the regional distribution of load growth. Long-term forecasting is particularly germane to the kind of analysis, described in Supplemental Paper No. 7, that considers the merits of postponing Tarbela to a later date: benefits are considerable if Tarbela is completed in 1975, but would they be even greater if the project were postponed to, say, 1985? The evidence clearly favors the earlier date, provided, however, that the various assumptions and projections used prove reasonably realistic.

The Study Group's decision to carry out its own studies of the macroeconomic framework could be justified on one issue alone: the importance of achieving the greatest accuracy possible in the long-term forecast of the power load. For this reason, the methodology of power forecasting used is presented in some detail in Supplemental Paper No. 2. Because power projects were selected on the basis of meeting the forecast load at least cost, the calculation of benefits was almost entirely internal to the power sector once the load forecast had been made. Thus, the physical load forecast becomes a key element of decision making. If, in reality the forecast should turn out to have been too high, investment funds will have been wasted; if too low, the lack of power may cause serious disruption in the rest of the economy. Thus, the methodology places on the load forecast the burden of ensuring balance between the growth of the power sector and the growth of other sectors of the economy.

The Cost Price Problem

From the outset of the Study it was recognized that all analyses would need to be made in terms of the real economic costs of alternatives. For such economic comparisons, costs were to exclude transfer payments such as import duties, sales taxes and interest during construction. Only the financing requirements of projects and programs were to include these transfer payments. In selecting or calculating economic prices for the comparison of alternatives, the Study Group tried to approximate opportunity costs that would represent the value of factors in alternative uses: for example, hired labor was priced at current rural wage rates while family labor was assumed to be available free.

In determining proper costs or prices there were many uncertainties which could only be solved on the basis of experienced judgment. For instance, the cost of engineering constructions were all estimated on the basis of uniform 1965 prices for comparable work and on the assumption that increases in unit prices would affect all works compared in a similar way. Such an approach was less reasonable for agricultural crop prices, the differential among which may well change over the years. 1965 farm prices were in fact taken for most crops, but where change seemed particularly likely—e.g., downward for rice and upward for meat—special adjustments were made. Another problem, relating more particularly to the costs of engineering works, arose from the very varying amounts of knowledge and experience that exist regarding the different projects considered. Very large amounts of money had been spent on engineering studies of the Tarbela Project, but relatively little had been spent to firm up the costs of most other surface storage projects. Or again, in the case of irrigation works, considerable experience had been accumulated regarding the costs of tubewells—though there is still room for disagreement about these costs—whereas there had been practically no experience with large-scale canal remodeling. Securing comparable cost estimates proved a difficult task throughout the Study. Rather crude techniques often proved the best approach: taking price ranges, changing contingency allowances, etc., and always coming back after making a comparison to reassess its validity.

Considering the importance of specific resource limitations, such as for water, fuel, implementation capacity, capital and foreign exchange, it was apparent from the start that very careful study would have to be made of prevailing market prices. And where actual prices were judged to be out of accord with the real scarcity of a commodity, the question of how to calculate shadow prices loomed large in the thoughts of the Study Group. The normal approach of economics to shadow pricing—that the scarcity value of a factor should represent its marginal productivity value after all alternative uses for it have been taken into account—was not easily applicable in practice. For purposes of the Special Study, the use of an optimizing model to determine shadow prices would have been desirable; for the long analytical periods covered, such a model could anticipate changing degrees of scarcity over a relatively long period of time. However, the Planning Commission's long-term macroeconomic models were not sufficiently advanced to indicate specific scarcity values. The best that could be achieved was to relate general indications of long-term scarcity as reflected in Perspective Planning to the specifics of current shortages. Once this had been done and rough scarcity prices determined, wherever possible the degree to which analytical results were sensitive to the assumptions chosen was examined. Supplemental Paper No. 3 has been incorporated to show the exercise carried out with regard to fuel prices. Appendix 1 to Supplemental Paper No. 1 gives the results of another, relating to foreign exchange.

Some headway was achieved with more sophisticated techniques of measuring shadow prices for the particular sector of agriculture. In the tests of economic efficiency described later in this Volume, economic values were derived for surface water, the implementation constraint as it affected the size of the public tubewell programs, and the budgetary constraint. However, for capital for most of the Study —e.g., in the comparison between alternative investments, and also, in fact, in the determination of the absolute size of the water and power investment program—a cost of capital was used which was considered merely to be a rough measure of the social value of foregone investments; i.e., investments that would be precluded by the execution of the water and power development program being prepared. In the selection of the 8 percent discount rate used, the Study Group was conscious of two needs: one was to give due recognition to the relative scarcity of capital in the Pakistan economy, and the other was to maintain, as far as possible, a neutral project-selection process. As for the latter concern, the selection of a too high rate, for example, would tend to bias analyses against the longer lived alternatives such as storage reservoirs and hydroelectric plant which are relatively expensive in capital cost and relatively cheap in operating cost. The 8 percent rate is somewhat above the prevailing rate of interest on Government bonds in Pakistan and somewhat below typical rates of return on private investment. Projects yielding less than an 8 percent rate of return were thus automatically excluded from the program. Although complexities of the Study precluded comprehensive sensitivity tests for all the proposed investments, some preliminary tests tended to show that the investment plans as proposed are not very sensitive to variations of the discount rate within a range of, say, 6 to 10 percent.

The Study Group used similarly crude procedures to measure the scarcity value of the foreign exchange components of both current and capital costs. After a study of the current foreign exchange situation (a short summary of which is presented in Annex 2 of Supplemental Paper No. 1), the Study Group concluded that the system of foreign exchange rationing in force—involving import licenses, tariffs and indirect taxes—implied an effective scarcity value of foreign exchange of about twice the official rate of exchange. Perhaps the most interesting phase of this exercise related to its effect on the economic price for fuel which was especially significant for the power analyses carried out. The net power benefits attributable to Tarbela were found to be very sensitive to changes in the assumption with regard to fuel price. For example, benefits range from about $40 million at a fuel price of 20 cents per million BTU to about $220 million at a fuel price of 70 cents, with calculations using the current foreign exchange rate. The Study Group's approach to this problem as outlined in Supplemental Paper No. 3 focuses on the sacrifice to the West Pakistan economy that is involved by using gas for electric power generation now, instead of conserving it to some later date. On the basis of a crude forecast of the overall energy balance (presented in Supplemental Paper No. 3), the Study Group estimated that, considering present commitments and forecast nonelectrical demands for gas, the currently estimated reserves would be used up by the year 2000. In other words, gas used for power generation now can be equated with the importation of fuel in 2000. Therefore, the value of gas at any time may be regarded as the present worth—in the year the gas is used—of the cost of importing an equivalent amount of oil in 2000. So the key to these calculations becomes an assumption in regard to the real cost to Pakistan of importing oil in 2000. As explained in Supplemental Paper No. 3, the current international price for fuel oil in terms of US dollars of current value, appears appropriate for purposes of long-range planning. But to convert this dollar price into a price representing the real cost to Pakistan, an appropriate economic value must be set for the foreign exchange requirements. Currently, West Pakistan is devoting about 3 percent of available foreign exchange to fuel imports. Given the overall balance between supply and demand, it seemed appropriate to value this foreign exchange expenditure at twice the official rate. As long as fuel imports remain within 3 percent of total imports, the doubled rate could continue to be used on the assumption that it represents some optimality of allocation. But fuel imports in excess of the 3 percent level would affect the general scarcity value of foreign exchange, and so such imports would have to be valued at a higher rate. And to complete the argument, once natural gas reserves are exhausted, fuel imports to replace gas used for power will, in fact, be *additional* imports—i.e., beyond the assumed 3 percent level. It was estimated that additional imports might double the present level. Thus, on the basis of this relatively crude approach, the Study Group concluded that it would be reasonable to use a foreign exchange rate in these particular calculations of double the current shadow rate used elsewhere: i.e., the rate used in this illustration (see Supplemental Paper No. 3) was four times the official rate. Such adjustments can have important consequences, as will be made clear in this Volume.

SUPPLEMENTAL PAPER I

Macroeconomic Framework

The Pattern of the Economy

West Pakistan has a population of some 55 million people and an annual per capita income equivalent to about $90 at the official exchange rate. The population is somewhat smaller than that of East Pakistan, while the per capita income is somewhat greater. The population of West Pakistan is believed to be growing at a rate in the neighborhood of 2.6-3 percent per annum.

Between 1950 and 1965 the real income of West Pakistan grew at an average rate of about 4 percent per annum, or about 1.5 percent faster than the growth of population. However, around 1960 there was a significant change in the trend of growth. Over the ten years before 1960 the rate of growth in provincial output averaged only a little over 3 percent per annum; in the five years 1960–65 an average growth rate of nearly 6 percent was achieved. The change in trend was not confined to any one sector. Agricultural output grew between 1960 and 1965 at an average rate of about 3.8 percent—or more than twice the rate of the previous decade. Manufacturing industry, though it started from an extremely small base in 1950, also grew faster between 1960 and 1965 (about 11.5 percent per annum) than between 1950 and 1960 (about 8 percent per annum). The other sectors of the economy also show a sharp acceleration in growth around 1960 from an average 4 percent in the preceding decade to more than 6 percent in the succeeding five years. Production of electricity increased extremely rapidly throughout the period—over 20 percent per annum on average—but whereas the growth rate fell to around 16 percent between 1955 and 1960 it rose again in the early 1960's to about 20 percent per annum.

The structure of the West Pakistan economy changed significantly over the 15-year period ending in 1965. Table 1-1 summarizes the broad changes, and Table 1-21 at the end of this section (page 45) shows the changes in greater detail. Most strikingly, as with most developing countries, agriculture has become a less important sector in terms of its contribution to total output, accounting for only about 42 percent of total provincial output in 1965 compared with 54 percent in 1950. Manufacturing industry has doubled its share of provincial product over the same period, reaching about 18 percent by 1965. The sharp growth of construction as a proportion of total economic activity, the relative stability of transport, and a small but noticeable fall in the share of Government are other striking trends revealed by Table 1-1.

Table 1-1 shows clearly that the most dynamic major sector of the economy has been manufacturing industry. Actually, the table fails to bring out fully the magnitude of the achievement in industrial development. West Pakistan manufacturing

TABLE 1-1
ECONOMIC STRUCTURE OF WEST PAKISTAN, 1950–65
(percent of GPP at factor cost)

	1949/50	1959/60	1964/65
Agriculture	54.3	46.3	41.8
Manufacturing and Mining	8.5	13.6	17.6
Construction	1.5	2.6	4.1
Transport and Communication	5.0	5.5	5.3
Government	5.0	4.7	4.4
Other Services	25.7	27.3	26.8

industry is composed of two very different subsectors—one, small-scale industry, about which little is known but which is believed to be growing at about the same rate as the population, and the other, modern large-scale industry. It is this second class of manufacturing industry which has shown dramatic growth; it has been built up from almost nothing in 1950 to about 12 percent of total output in 1965. It achieved a growth rate of about 16 percent per annum during the Second Plan period (1960–65). Early growth of the large-scale manufacturing sector was largely in industries producing substitutes for imports. It was stimulated by the existence of a high protective tariff on consumer-goods imports as well as direct quantitative controls on all imports. Over the last decade, West Pakistan industry has come to make an increasingly important contribution to exports—chiefly in textiles, but also in fields such as light engineering goods, and rubber and leather products. Growth of large-scale industry was further promoted during the Second Plan period by improved institutional credit arrangements, the Export Bonus Scheme, tax holidays of some four to eight years on industrial investments, liberalization of import policy particularly for raw materials, and various other measures. Table 1-2 shows the structure of the large-scale manufacturing sector in 1964/65. Table 1-2 illustrates the extremely important position of agricultural processing industry in West Pakistan and in particular of the industry based on domestically

TABLE 1-2
STRUCTURE OF THE LARGE-SCALE MANUFACTURING SECTOR, 1964/65
(percent of total value added)

Consumer Goods	52.8
Sugar	5.0
Tobacco	2.3
Textiles (80%)	21.3
Board, Paper	1.0
Other	23.2
Intermediate Goods	28.2
Fertilizer	1.1
Cement	2.1
Textiles (20%)	5.3
Cotton-Ginning	7.7
Chemicals and Refining	7.0
Other	5.0
Investment Goods	19.0

TABLE 1-3
WEST PAKISTAN: CONTRIBUTION OF AGRICULTURE TO GPP, 1960–65
(factor cost in Rs. million at constant 1959/60 prices)

	1959/60	1960/61	1961/62	1962/63	1963/64	1964/65	Average Rate of Growth 1960–65
Major Crops	3,882	3,840	4,209	4,595	4,509	4,888	4.7%
Minor Crops	893	869	918	891	1,129	1,130	4.8%
Livestock[a]	2,837	2,887	2,940	2,996	3,048	3,121	1.9%
Fishing	71	67	70	77	85	91	5.1%
Forestry	28	32	34	38	42	46	10.4%
Total	7,711	7,695	8,171	8,597	8,813	9,276	3.8%

[a] See footnote to text.

produced cotton (cotton-ginning and most of the textile industry), which alone accounted for about one-third of total output of the large-scale manufacturing sector in 1964/65. The relatively high proportion of total output accounted for by the investment goods industry—mainly transport equipment, light electrical equipment and industrial and agricultural machinery—is mainly a development of the last decade.

Despite the rapid growth of manufacturing industry in West Pakistan, agriculture still remains very much the dominant sector of the economy, as Table 1-1 made clear. There are about five million farms—most of them at least partially irrigated—and on these farms live nearly three-quarters of the Province's population. Much of the activity elsewhere in the economy is intimately linked to agriculture, in the form of providing services to the agricultural sector, processing the agricultural commodities produced or distributing them, as illustrated in the preceding paragraph in the case of large-scale manufacturing industry. Estimates of the composition of agricultural output indicate that about 65 percent may come from crops and most of the remaining 35 percent from livestock.[1] Table 1-3 shows the main directions of recent growth in agriculture (*cf.* Volume II). Most of the growth in agricultural production in the Second Plan period occurred in the crop sector, according to these estimates. It is shown in Volume II that increases in production

[1] The figures on the livestock sector are probably some of the most doubtful in the national accounts and little reliability can be attributed even to the rate of growth implied. The data on the livestock sector are based primarily on the livestock censuses of 1945 and 1955 and the Agricultural Census of 1960. This last census was carried out on a sample basis. After preliminary tabulation of the sample results, it was found that a substantial underenumeration had occurred in the case of livestock. To correct this, correction factors called "ratio estimates" based on the relationship of total acreage to enumerated acreage in each district were applied to obtain the desired coverage. Since the relationship between the acreage and livestock is not necessarily invariant, the application of ratio estimates has probably led to an overestimation of livestock. The production of certain livestock products is estimated on the basis of very high ratios of output per animal. Tending in the opposite direction—towards underestimation of actual output of the livestock sector—is the fact that the Central Statistical Office has made no adjustment for the growth of the livestock population, as reliable data on the rate of their growth are not available. Khan and Bergan comment that the overestimation of base year animal population and production per animal may be balanced out by the failure to allow for increase in the livestock population. (See Taufiq M. Khan and A. Bergan "Measurement of Structural Change in the Pakistan Economy: A Review of the National Income Estimates, 1949/50–1963/64" and references therein cited.)

of sugarcane, wheat and rice accounted for most of the growth. Production of sugarcane increased dramatically from a Plan benchmark figure of 11.6 million tons in 1959/60 to 18.4 million tons in 1964/65. Production of rice failed to meet Plan targets but nevertheless it increased some 25 percent over the Plan period. Wheat production increased relatively modestly in percentage terms, but the crop is so important in the total output of agriculture that it accounted for a significant portion of total growth. Production of cotton, by contrast, increased greatly in percentage terms but it was less important than the above mentioned crops in terms of contribution to the overall increase in agricultural output.

The various facets of the contribution that agriculture makes to economic growth in West Pakistan are discussed below in reference to the implications of the programs proposed in this report for the future growth of the economy, but first it is necessary to discuss briefly the broader aspects of the base for future growth that was established during the Second Plan period. Table 1-4 shows the trend of events in those years. Perhaps the most notable achievements were in exports and in investment. Table 1-4 shows the growth of exports to foreign countries and to East Pakistan in terms of current prices; both show substantial increases over the Plan period, with foreign exports growing a little less than 8 percent per annum and exports to East Pakistan growing at an average rate of about 9 percent per

TABLE 1-4
ESTIMATED GROSS PROVINCIAL PRODUCT AND EXPENDITURE, 1960–65
(Rs. million in current prices)

	1959/60	1960/61	1961/62	1962/63	1963/64	1964/65
Gross Provincial Product (factor cost)	16,640	18,550	20,000	21,210	22,700	25,010
Indirect taxes, net of subsidies	901	1,077	1,198	1,352	1,550	1,990
Gross Provincial Product (market prices)	17,541	19,627	21,198	22,562	24,250	27,000
of which:						
Exports abroad	970	685	785	1,070	1,265	1,415
Exports to E.P.	707	1,023	1,062	1,190	1,112	1,090
Imports from abroad	2,280	2,570	2,750	3,510	3,610	3,920
Imports from E.P.	388	394	432	507	548	576
Import Surplus	991	1,256	1,335	1,757	1,781	1,991
Disposable Resources	18,532	20,883	22,533	24,319	26,031	28,991
Investment	2,075	3,185	3,795	4,440	4,790	5,420
fixed	2,055	3,025	3,525	4,410	4,750	5,260
stocks	20	160	270	30	40	160
Consumption	16,457	17,698	18,738	19,879	21,241	23,571
Savings	1,084	1,929	2,460	2,683	3,009	3,429
Transfer to E.P.	319	629	630	683	564	514
Foreign Current Deficit	1,310	1,885	1,965	2,440	2,345	2,505
In % of GPP (market prices)						
Fixed Investment	11.7	15.4	16.6	19.5	19.6	19.5
Savings	6.2	9.8	11.6	11.9	12.4	12.7
Exports abroad	5.5	3.5	3.7	4.7	5.2	5.2
Imports from abroad	13.0	13.1	13.0	15.6	14.9	14.5
Marginal savings rate		40.5	33.8	16.3	19.3	15.2

Sources: Estimated on the basis of publications of the Pakistan Planning Commission and the Central Statistical Office together with supplementary information provided by the Planning Commission.

TABLE 1-5
WEST PAKISTAN'S ESTIMATED VISIBLE EXPORTS, 1960–66
(Rs. million in current prices)

	1959/60	1960/61	1961/62	1962/63	1963/64	1964/65	1965/66
Agricultural Products	321	341	385	729	643	619	591
Raw Cotton	184	134	121	366	373	287	277
Raw Wool	75	71	69	85	75	59	60
Hides and Skins	42	27	38	25	25	27	26
Rice	—	49	87	173	106	122	133
Fresh Fish	20	19	21	27	32	39	46
Fruits and Vegetables	n.a.	4	5	6	7	7	7
Other	n.a.	37	44	47	61	78	42
Other Raw Materials	n.a.	28	30	40	49	56	52
Manufactured Goods	231	170	127	227	377	462	558
Cotton twist and yarn	175	74	10	20	99	139	103
Cotton piece goods	56	45	33	68	90	133	148
Other	n.a.	51	84	139	188	190	307
Miscellaneous	n.a.	1	1	2	6	3	3
Total	763	540	543	998	1,075	1,140	1,201

Sources: Ministry of Finance, Pakistan Economic Survey 1965/66 Central Statistical Office, Monthly Statistical Bulletins.

annum. In constant price terms foreign exports seem to have grown at slightly more than 9 percent. Exports of agricultural commodities, in raw form, made a more than proportionate contribution to this increase, rising from Rs. 320 million in 1959/60 to Rs. 620 million in 1964/65; the most important contributions to the increase in export earnings in absolute terms were made by raw cotton, exports of which rose from Rs. 184 million to Rs. 287 million, and by rice, exports of which rose from nothing in 1960 to about Rs. 120 million in 1964/65 (see Table 1-5). Exports of cotton manufactures, while they failed to achieve the Plan targets, still made a significant contribution to the increase in total export earnings. The other two important items in the increase of foreign exchange earnings were invisible earnings—especially emigrants' remittances—and miscellaneous manufactures. Invisible earnings approximately doubled from their 1959/60 level of about Rs. 170 million. Miscellaneous manufactures—mainly items such as carpets, sports goods, musical instruments, medical instruments, footwear and leather goods, small electrical equipment, domestic utensils, diesel engines and rubber tires and tubes—rose from an insignificant amount in 1959/60 to nearly Rs. 200 million in 1964/65. The figures for 1965/66 in Table 1-5 show that this group of exports continued to rise impressively through the first year of the Third Plan.

Total fixed investment increased more than 150 percent—or by about 20 percent per annum—between 1959/60 and 1964/65. A sizeable portion of this investment was in the Indus Basin Works, but, even if this is left out of account, investment still increased at an average rate of about 16 percent per annum. Savings may have risen even more rapidly than investment. The data in Table 1-4 suggest a marginal savings rate between 1959/60 and 1964/65 of 25 percent, but 1959/60 savings may have been exceptionally low. Nevertheless it is clear that a marginal savings rate in the neighborhood of 20 percent was achieved, implying an average savings rate at the end of the Plan period of about 12.5 percent. However, the gap between savings and investment grew over the Plan period from about Rs. 1 billion in 1959/60 to about Rs. 2 billion in 1964/65. Because West Pakistan made transfers of increasing size to East Pakistan the deficit on foreign account was somewhat in excess of these levels. It rose from an estimated Rs. 1.3 billion ($275 million) in 1959/60 to about Rs. 2.5 billion ($525 million) in 1964/65. Foreign assistance did in fact play a major role in the Second Plan period. On a national basis Pakistan received, during the course of the Plan period, about $2 billion in foreign aid, excluding receipts from the Indus Basin Fund. This was about twice the aid made available to Pakistan during the First Plan period. On a per capita basis, the annual flow of aid to Pakistan increased from a little over $2 in the year 1960/61 to more than $5 in 1964/65. Disbursements from the Indus Basin Development Fund during the Second Plan added about another $575 million to the total capital inflow.

Over the years, and especially during the Second Plan period, Pakistan's Five Year Development Plans have come to play an increasingly important part in the total development effort of the country. The Plans are concerned with setting the overall financial and economic framework of the development effort, establishing specific financial and physical targets, allocating Government development expenditures and proposing policies which will promote economic growth. The First Five Year Plan covered the period 1955–60, but the results were disappointing. The Second Five Year Plan, covering the period 1960–65, was given much greater emphasis by the Government, and many of the policies recommended by the Planning Commission in the Plan document and generally endorsed by the National Economic Council were subsequently officially adopted as part of the national development effort. Plan investment targets were considerably exceeded, although there was a slight shortfall from the target in public sector investment. Despite this shortfall public development expenditures in West Pakistan during the Second Plan were more than twice what had been achieved during the First Plan, as illustrated by Table 1-6, which also shows the latest Third Five Year Plan figures for the sake of comparison. Besides the great increase in the size of public development expenditures, the table also indicates the shares of the total allocated to Agriculture, Water and Power, the chief sectors with which we are concerned here. These sectors maintained an approximate 50 percent share of the total through the First and Second Plan periods. Expenditures shown for those periods are actual expenditures. Expenditure on agriculture during the Second Plan did fall seriously short of the target, but this was more than made up by above-target public investment expenditures in the Water sector. The Third Plan, as recently revised, allocates between sectors total public development expenditures for West Pakistan about 80 percent above those achieved in the Second Plan. Investment in water projects has a slightly reduced share, while Agriculture and Transport have been allotted larger proportions of the total than they received during the Second Plan. Education has a somewhat increased share, but less than it was originally intended to receive.

In the course of preparing the Third Five Year Plan the need was felt for a framework which could give explicit recognition to objectives and major structural changes which could not be expected to be achieved in as short a span as five years. Many of the decisions which were taken for the short-term would have a critical effect in confining or expanding the scope for choices at a later date and the realization developed that to see the full implications of current recommenda-

TABLE 1-6
ESTIMATED PUBLIC SECTOR DEVELOPMENT EXPENDITURE[a]
(Rs. million)[b]

	First Plan	Second Plan	Third Plan[c]
	(1955–60 Actual)	(1960–65 Actual)	(1965–70 Projected)
Agriculture	490(14)[d]	904(11)	1,816(13)
Water	1,240(36)	1,658(21)	2,211(15)
Power		1,194(15)	2,176(15)
Industry and Mining	405(12)	669(8)	1,348(9)
Transport and Communication	735(22)	1,629(21)	3,431(24)
Housing and Settlements	385(11)	951(12)	1,113(8)
Education and Training	123(3)	456(6)	1,066(7)
Health	43(1)	183(2)	544(4)
Manpower and Social Services	5(1)	22(1)	75(1)
Works Program	—	200(2)	620(4)
Total	3,426(100)	7,866(100)	14,400(100)

[a] "Development Expenditure" is a budgetary classification in Pakistan which includes all non-defense public investment and some current expenditure considered of a "development" nature—e.g., extension service, fertilizer and pesticide subsidies.
[b] First and Second Plan figures are in current prices, while Third Plan figures are in 1964/65 prices.
[c] As revised December 1966.
[d] Figures in parentheses represent percentages of total development expenditure.

tions it was necessary to have a longer term view. Considerable effort was therefore devoted to formulation of a long-term plan built around the major objectives of the country. It was envisaged that the skeleton framework formulated in the long-term plan as a means of attaining these objectives would gradually be filled out by various Master Plans that would go into greater detail on the development potential of the different sectors of the economy. The Planning Commission chose a 20-year perspective for the long-term or Perspective Plan.

The objectives of the Perspective Plan are mainly national objectives, as opposed to objectives for West Pakistan, and at the time this Study was underway, the Planning Commission was still working on the regional breakdown of the Perspective Plan so that no definitive framework for West Pakistan was available. However, with help from the Planning Commission, a rough version of a projection for West Pakistan was built up which would be consistent with the Perspective Plan for the whole of Pakistan. The main objectives which were taken into account in the formulation of this projection are those spelled out in the official presentation of the Perspective Plan in the Third Plan document and adjusted for application to West Pakistan.

1. An approximate doubling of per capita income between 1965 and 1985, which, in the case of West Pakistan, with a projected population growth rate somewhat higher than that actually used by the Planning Commission (Annex 1), would involve more than tripling the GPP.

2. The provision of full employment at the earliest achievable date. The target stated in the Plan is full employment (i.e. unemployment rate of 5 percent) by 1975. The current level of unemployment in terms of man-years of work available is estimated by the Planning Commission at 16 percent.

3. Parity in per capita incomes between East and West Pakistan. The Third Plan document cites per capita income in East Pakistan in 1964/65 as Rs. 340 as opposed to Rs. 442 in West Pakistan.

4. More equitable income distribution. The Third Plan document states that 24 percent of the people in West Pakistan have monthly family incomes of less than Rs. 100. It also refers to Planning Commission studies which indicate that 10 out of the 51 districts in West Pakistan have a lower per capita income than the lowest in East Pakistan. For the purposes of this study, this objective was therefore interpreted as being to raise all families' income levels and in particular to raise those with family incomes less than Rs. 100 per month above that level.

5. Universal literacy, which is apparently taken to mean universal eight-year education by 1985. This is regarded, for the purposes of this study, as meaning a substantial expansion in expenditures on education from their present rather low level.

6. Institutionalization of the economic growth process, in the sense of making it increasingly dependent on West Pakistan's own resources of savings, skills and industrial production. The specific target set to express this objective is elimination of net capital inflows on public account by 1985.

Tables 1-7 and 1-8 present the Study Group's understanding of the implications of the Perspective Plan for West Pakistan. Table 1-7 shows projected GPP growing at a little over 6 percent per annum. Exports would grow at an average rate of about 8-9 percent, but higher in the early part of the Plan period; imports would grow at an average rate of only about 2.6 percent and imports from abroad even more slowly, on average. (It should be noted that the figures for the Third Plan period are somewhat distorted by the fact that Indus Basin Works expenditures, which for instance represent about Rs. 900 million of investment in 1964/65, are expected to fall to about Rs. 300 million by 1969/70 and imports on this account will fall commensurately.) After 1975 West Pakistan would generate a growing surplus on foreign exchange account to meet, by 1985, the last of the targets listed above. Throughout the Perspective Plan period West Pakistan would be making increasing transfers to East Pakistan. In order to enable these objectives to be achieved investment in West Pakistan, as a proportion of GPP, would not increase from the 1965 level (19.5 percent including the Indus Basin Works investment) but savings would rise quite rapidly, reaching an average level of about 22 percent by 1985.

Table 1-8 shows the Study Group's understanding of the sectoral growth rates for the West Pakistan economy implied by the Perspective Plan. The table indicates the relatively high growth rate in agriculture, between 5 and 5.5 percent, which has been adopted by the Planning Commission as a basic requirement, because of the importance of the sector in the economy and because of its potential role in raising export earnings and thus preventing the foreign resource gap from becoming a constraint on domestic saving. It also indicates the relatively low rate of growth in manufacturing industry (by comparison with past performance), which is apparently implied by the Perspective Plan, and also the heavy concentration of industrial growth in import-substituting industries in the fields of intermediate goods and capital goods.

The lower portion of Table 1-8 represents a conversion of the projections in the top portion into categories consistent with those used in the input-output projection model which was employed by the Planning Commission to assist in the formula-

TABLE 1-7
Perspective Plan Projection
(Rs. million, 1964/65 prices)

	Gross Provincial Product and Expenditure, 1965–85									Average Growth
	1964/65		1969/70		1974/75		1979/80		1984/85	1965–85
Gross Provincial Product (factor cost)	25,010	(6.1)	33,600	(6.2)	45,400	(6.3)	61,600	(6.0)	82,400	6.1
Indirect Taxes, net of subsidies	1,990	(5.5)	2,600	(6.1)	3,500	(6.1)	4,700	(5.7)	6,200	5.8
Gross Provincial Product (market prices)	27,000	(6.0)	36,200	(6.2)	48,900	(6.3)	66,300	(6.0)	88,600	6.1
Of Which:										
Exports	2,505	(11.5)	4,310	(6.3)	5,844	(7.1)	8,220	(6.9)	11,500	7.9
Abroad	1,415	(12.1)	2,510	(7.5)	3,614	(7.6)	5,220	(7.5)	7,500	8.7
to E.P.	1,090	(10.6)	1,800	(4.4)	2,230	(6.1)	3,000	(5.9)	4,000	6.7
Imports	4,496		4,260	(8.8)	6,494		6,420	(3.2)	7,500	2.6
from Abroad	3,920		3,490	(9.4)	5,464		5,040	(2.3)	5,650	1.8
from E.P.	576	(6.0)	770	(6.0)	1,030	(6.0)	1,380	(6.0)	1,850	6.0
Import Surplus	1,991		−50		650		−1,800		−4,000	—
Disposable Resources	28,991	(4.5)	36,150	(6.5)	49,550	(5.4)	64,500	(5.6)	84,600	5.5
Investment	5,420	(0.2)	5,480	(11.5)	9,450	(4.7)	11,900	(5.1)	15,300	5.3
fixed	5,260	(0.1)	5,280	(11.7)	9,200	(4.7)	11,600	(5.0)	14,800	5.3
stocks	160	(4.6)	200	(4.6)	250	(3.7)	300	(10.8)	500	5.9
Consumption	23,571	(5.4)	30,670	(5.5)	40,100	(5.6)	52,600	(5.7)	69,300	5.5
Savings	3,429	(10.0)	5,530	(9.7)	8,800	(9.3)	13,700	(7.1)	19,300	9.0
Transfer to E.P.	514	(14.9)	1,030	(3.1)	1,200	(6.2)	1,620	(5.8)	2,150	7.4
Foreign Current Deficit	2,505		980		1,850		−180		−1,850	
As % of GPP (market prices)										
Fixed Investments	19.5		14.6		18.8		17.5		16.7	
Savings	12.7		15.3		18.0		20.7		21.8	
Import Surplus	7.4				1.3					
Exports Abroad	5.2		6.9		7.4		7.9		8.5	
Imports from Abroad	14.5		9.6		11.2		7.6		6.4	
Marginal Savings Rate		22.8		25.7		28.2		25.1		
Marginal Import Rate		−2.5		17.6		−0.4		4.8		

TABLE 1–8
PERSPECTIVE PLAN PROJECTION
(Rs. million, 1964/65 prices)

	Gross Provincial Production by Sector of Origin									Implied Average Annual Growth
	1964/65		1969/70		1974/75		1979/80		1984/85	1965–85
Agriculture	10,470	(5.4)	13,600	(5.4)	17,700	(5.6)	23,200	(5.0)	29,600	5.3
Mining and Quarrying	125	(9.9)	200	(8.5)	300	(8.5)	450	(7.6)	650	8.6
Manufacturing—Large	3,275	(8.6)	4,940	(9.1)	7,650	(8.3)	11,400	(7.8)	16,600	8.4
Consumer Goods	1,760	(3.5)	2,090	(2.4)	2,350	(2.1)	2,600	(2.2)	2.900	2.5
Intermediate Goods	785	(10.6)	1,300	(12.1)	2,300	(7.5)	3,300	(2.3)	3,700	8.1
Capital Goods	730	(16.3)	1,550	(14.1)	3,000	(12.9)	5,500	(12.7)	10,000	14.0
Manufacturing—Small	1,150	(1.8)	1,260	(1.4)	1,350	(0.0)	1,350	(0.0)	1,350	0.8
Public Utilities	190	(13.7)	400	(11.9)	700	(11.4)	1,200	(10.8)	2,000	12.5
Construction	1,019	(6.1)	1,370	(6.0)	1,833	(6.3)	2,486	(6.0)	3,330	6.1
Transport and Communications	1,294	(6.2)	1,750	(6.2)	2,360	(6.3)	3,204	(6.2)	4,330	6.2
Other Services	7,487	(6.4)	10,080	(6.0)	13,507	(6.3)	18,310	(6.0)	24,540	6.1
Gross Provincial Product (factor cost)	25,010	(6.1)	33,600	(6.2)	45,400	(6.3)	61,600	(6.0)	82,400	6.1
Indirect Taxes	1,990	(5.5)	2,600	(6.1)	3,500	(6.1)	4,700	(5.7)	6,200	5.8
GPP (market prices)	27,000	(6.0)	36,200	(6.2)	48,900	(6.3)	66,300	(6.0)	88,600	6.1
Reconsolidation in Sectoral Groups Used in Input-Output Analysis										
Agriculture	10,470	(5.4)	13,600	(5.4)	17,700	(5.6)	23,200	(5.0)	29,600	5.3
Consumer Goods Manufacturing[a]	2,853	(2.9)	3,287	(2.0)	3,633	(1.3)	3,883	(1.5)	4,183	1.9
Intermediate Goods Manufacturing[b]	1,100	(11.5)	1,900	(11.7)	3,300	(8.5)	4,950	(5.1)	6,350	9.2
Investment Goods Manufacturing[c]	787	(15.4)	1,613	(13.7)	3,067	(12.7)	5,567	(12.6)	10,067	13.6
Construction	1,019	(6.1)	1,370	(6.0)	1,833	(6.3)	2,486	(6.0)	3,330	6.1
Transport and Communications	1,294	(6.2)	1,750	(6.2)	2,360	(6.3)	3,204	(6.2)	4,330	6.4
Other Services	7,487	(6.1)	10,080	(6.0)	13,507	(6.3)	18,310	(6.0)	24,540	6.1
Total	25,010	(6.1)	33,600	(6.2)	45,400	(6.3)	61,600	(6.0)	82,400	6.1

[a] i.e., Consumer goods portion of large-scale manufacturing plus 95% of small-scale manufacturing.

[b] Large-scale intermediate goods, mining and quarrying, plus utilities.

[c] Large-scale capital goods plus 5% of small industry.

tion of the Third Five Year Plan. This projection model,[1] which is described in outline in the following paragraphs, has been used by the Study Group to relate the findings of the Study in regard to the growth potential of the agricultural sector in West Pakistan to the existing economic plans.

THE PROJECTION MODEL

The model is of the linear inter-sectoral type and relates macroeconomic magnitudes such as the overall growth rate or the savings rate to a sectoral growth pattern which balances the supply and demand relationships between sectors. The model is static in that it projects such a consistent growth pattern for a particular point of time, yielding no information about the path of transition. For instance, as employed in the formulation of Pakistan's Third Five Year Plan it took the economy of 1964/65 as given in its aggregates, its sectoral structure and past trends in the development of intersectoral deliveries of goods and services and asked what changes must occur before the end of the planning period in order to achieve consistency between overall growth targets, attainable savings performance, the development of the balance of payments and the whole pattern of intersectoral demand and supplies.

As used by the Planning Commission, the model differs from others of the input-output type in that it is not based on a single year's input-output table, but on two —one for the beginning and one for the end of the Second Five Year Plan period. These tables were aggregated to seven producing sectors and a large number of the model's equations is based on *marginal* input-output coefficients derived from comparisons between the two tables. This approach is intended to capture the effects of structural changes in the economy in an otherwise highly aggregated intersectoral model. However, the use of marginal coefficients had the disadvantage of implying changing elasticities for the interindustry delivery coefficients with all of them tending toward unity over time. This feature of the model confines its use to medium term projections. In the derivation of a consistent set of sectoral outputs and economic aggregates, the model starts from growth targets for national income, aggregate savings, and agricultural production as well as projections of the attainable exports in all sectors except agriculture. On the basis of incremental capital-output ratios in each sector and information about average gestation periods of new investments the gross investment required to support the projected income increase can be estimated. Given the aggregate savings target, the domestic-resources gap in the year for which the projections are made can be computed. At the same time this gap would indicate Pakistan's net foreign assistance requirements in that year. Given the target level of agricultural production in the reference year the behavioral and technological relationships specified in the model allow the computation of the domestic demand for agricultural products, both for final consumption and for intermediate use, which would correspond to the target income level. The difference between production and effective domestic demand is considered in the model as available for export. With other exports having been already determined outside of the analysis, the total export earnings in the reference year can be computed. However, it remains for a separate analysis to determine whether the projected level

[1] The model was formulated by Wouter Tims of the Harvard Advisory Group, attached to the Planning Commission.

of agricultural exports will actually be attainable given Pakistan's export crops and the expected world market conditions. On the basis of specific coefficients, which indicate the average and marginal import requirements of production and consumption, the total import requirements are computed in the model. A comparison between total export earnings and total import expenditures yields the balance of payments deficit on current account, or the foreign exchange gap. Thus, the model computes both a domestic resources gap and a foreign exchange gap.

In the planning context, a foreign exchange gap which exceeds the size of the domestic resources gap would indicate the need for additional import substitution. However, a stepped-up program of import substitution will increase the size of the domestic resources gap—these lines of domestic production are in general among the more capital intensive processes and will thus raise the total amount of investment required as well as the import demand. The system of simultaneous equations which describes the interrelationship of the various sectors and the economic aggregates allows for the consideration of these "feed-back" effects. At the same time as the model determines consistent levels for the various economic aggregates, it also allows the derivation of that sectoral composition of output, imports, consumption, investment and those levels of intersectoral deliveries which are consistent with the Plan targets and the economic aggregates determined in the analysis. Having obtained this solution, it is left to further analysis to judge whether the solution of the model represents a feasible solution, for instance with regard to the projected volume of agricultural exports or with regard to the required value of additional import substitution; and whether the overall strategy of economic growth which the model shows to be consistent with the Plan targets is the best course of development open to the economy.

It has already been noted that the model starts from an independent estimate of the attainable growth in agricultural production whereas production in all other sectors is viewed as depending upon the interrelationships described by the model. The fact that the target level of agricultural production in the reference year is introduced into the analysis as an exogenous factor, leaving it to the model to determine what the effective domestic demand for agricultural products will be under different assumptions about overall economic growth made the model very useful to the Study Group in an indicative analysis of the macroeconomic implications for West Pakistan of the proposed development program for irrigated agriculture and its projected output response. For this analysis the Study Group had to derive a set of coefficients which, when used in the projection model for the reference year 1975, would approximate the technological and behavioral relationships which could be expected to prevail in the West Pakistan economy.

There were, of course, considerable difficulties in preparing data for West Pakistan that would be of reasonable validity for use in this model. In the first place, the coefficients used in the Plan preparation were marginal coefficients. Two input-output tables had been prepared for Pakistan, one for 1960/61 and one for 1964/65. Base-year coefficients were computed for each table. Marginal coefficients were also derived from comparison of the two tables, representing, for instance, the relationship between the increase in deliveries from Sector A to Sector B between those years as a proportion of the increase in gross value of output of Sector B. The ratio between this marginal coefficient and the base-year coefficient for 1960/61 represented an elasticity of input use by Sector B of deliveries from

TABLE 1-9
West Pakistan Input-Output Table, 1962/63
(Rs. million, current prices)

Origin \ Destination	Agriculture	Consumer Goods Manuf.	Intermed. Goods Manuf.	Investment Goods Manuf.	Construction	Transport and Communications	All Other Services	Total Inter-industry Supply	Consumption	Investment in Fixed Assets	Export of Goods and services: Regional	Export of Goods and services: Foreign	Total Final Demand	Gross Value of Production
1. Agriculture	1,614	3,869	784	177	60	—	—	6,504	5,451	—	75	166	5,692	12,196
2. Consumer goods manufacturing	12	355	16	34	311	27	142	897	7,811	—	555	293	8,659	9,556
3. Intermed. goods manufacturing	251	866	248	32	448	121	—	1,966	116	—	209	270	595	2,561
4. Investment goods manufacturing	12	34	15	20	24	231	—	336	381	286	48	15	730	1,066
5. Construction	—	—	—	—	—	—	100	100	256	2,390	—	—	2,646	2,746
6. Transport and communications	185	216	140	37	564	61	73	1,276	297	175	96	56	624	1,900
7. All other services	1,300	807	236	65	31	52	6	2,499	4,209	319	208	235	4,971	7,470
Total interindustry demand	3,374	6,147	1,439	365	1,438	492	321	13,578	—	—	—	—	—	—
Gross value added	8,749	2,221	739	365	890	1,203	7,086	—	—	—	—	—	—	21,253
Indirect taxes less subsidies	−10	568	207	83	70	59	2	977	192	183	—	32	407	1,384
Imports of goods and services: Regional	20	149	25	2	—	11	20	227	280	—	—	—	280	507
Imports of goods and services: Foreign	63	471	151	251	348	135	41	1,460	681	989	—	—	1,670	3,130
Gross value of production	12,196	9,556	2,561	1,066	2,746	1,900	7,470		19,674	4,342	1,191	1,067	26,274	

Sector A. This elasticity was in turn applied to the base-year coefficient for 1964/65, on the assumption that the pattern of change which had occurred between the years 1960/61 and 1964/65 would continue through the end of the Third Five Year Plan period. Some adjustments were made where these seemed appropriate, but generally the derived coefficients were adopted unchanged.

There were two difficulties for the Study Group with this procedure. In the first place two input-output tables were not available for West Pakistan, only one—for the year 1962/63,[1] shown in highly aggregated form in Table 1-9—so that it was impossible to derive marginal coefficients for West Pakistan in the manner used by the Planning Commission for the whole country. In the second place, the Study Group desired to make projections over the time span covered by the proposed 10-year development programs for water and power, and clearly coefficients,

[1] The basic 1962/63 input-output table for West Pakistan was prepared by Ghulam Rasul of the Pakistan Planning Commission. It was a 70-sector table which the Study Group aggregated to 7 sectors for use with the projection model. The 7-sector version is given in Table 1-9. The data differ slightly from those shown in other tables in this Report. For instance they imply a slightly higher average rate of savings in 1962/63—about 13.1 percent—than was shown in Table 1-4 above for the same year—11.9. However the Study Group adopted all the data provided in the input-output table as the base of its projections.

TABLE 1-10
PERSPECTIVE PLAN OBJECTIVES FOR WEST PAKISTAN IN 1975
(in terms of 1962/63 prices)
(Rs. million)

	Base Year 1962/63	Growth Index	Growth Per Annum	Projected Year 1974/75
Gross Provincial Product by Sector of Origin				
Agriculture	8,749	182	5.1	15,920
Consumer Goods Manufacturing	2,221	144	3.1	3,200
Intermed. Goods Manufacturing	739	438	13.1	3,240
Investment Goods Manufacturing	365	630	16.5	2,300
Construction	890	236	7.4	2,100
Transport and Commun.	1,203	196	5.8	2,360
All Other Services	7,086	202	6.0	14,310
GPP (factor cost)	21,253	204	6.1	43,430
Indirect taxes	1,384	259	8.3	3,585
GPP (market prices)	22,637			47,015
External Trade				
Exports	2,258			5,748
abroad	1,067	330	10.5	3,521
to East Pakistan	1,191	187	5.4	2,227
Imports	3,637			5,912
from abroad	3,130	156	3.8	4,883
from East Pakistan	507	203	6.1	1,029
Import Surplus	1,379			164
Transfer to East Pakistan	684			1,198
Foreign Current Deficit	2,063			1,362
Savings and Investment				
Investment	4,372	206	6.2	9,008
fixed	4,342			8,758
stocks	30			250
Consumption	19,674			38,171
Savings	2,993	295	9.4	8,844

whether constant or marginal, derived on the basis of recent experience would be likely to be considerably less valid in ten years' time than in five years' time in an economy growing as dynamically as that of West Pakistan. Therefore the Study Group had to use a good deal of judgment in the derivation of coefficients for West Pakistan, and the procedures adopted are described in detail in the course of this Report. Because of the amount of judgment and guesswork involved the Study Group does not believe that the results it has derived can be more than indicative. Nevertheless these results provide some useful light on some of the broader questions that the Study Group wished to consider.

Agricultural Growth and Overall Growth

One of the major problems which it was desired to investigate was the implication of the agricultural growth rate projected in this Report for overall economic growth in West Pakistan. Volume Two projects the Gross Value of Production (GVP) of the agricultural sector to grow at 5.2 percent and value added in agriculture to grow at about 4.5 percent over the 20 years, 1965–85. As indicated above in Table 1-7 the Perspective Plan itself projects the growth of value added in agriculture at an average rate of about 5.3 percent over the same period.

The results of the Study Group's analysis have been shown in Figure A1-1 and further in Tables 1-10 and 1-11.[1] All projections were made on the assumption that agriculture would grow at about 4.5 percent per annum from 1965 to 1975. The vertical axis in the Figure represents the marginal savings rate between the base year of the projection, 1962/63 and the year 1974/75, which was projected; it is also the dividing line between the right-hand portion of the horizontal axis which measures the agricultural surplus in 1974/75, or the quantity of agricultural production in excess of domestic requirements and therefore available for export in that year, and the left-hand portion of the horizontal axis which measures the agricultural deficit in that year. The sharply sloping lines in the center of the figure indicate that combination of agricultural surplus and marginal savings rate which would be consistent with a particular growth in gross provincial product between 1964/65 and 1974/75. The more gently sloping lines indicate the corresponding amount of import substitution which will have to be achieved in addition to the level already achieved in the base year, in order to bring the foreign exchange gap into balance with the savings-investment gap in 1974/75; import substitution is measured in terms of the value of import-substitute goods which must be produced in that year. Thus the Figure shows that, for any given overall target growth rate, the agricultural surplus and the need for additional import substitution is greater the higher the marginal savings rate.

The marginal savings rate implicit in the Perspective Plan is in the neighborhood of 24 percent over the period 1965–75. The aggregate relationship shown in the figure suggests that, with this marginal savings rate, an overall growth rate in GPP of 5.8 percent is attainable without any increase or decrease in the net surplus of agricultural products available for export in 1962/63 and with additional import-substitution to the value of about Rs. 2,600 million. An overall growth rate of 6 percent could be attained, but it would involve additional imports (or reduced exports) of agricultural products of the order of Rs. 500 million and import substitu-

[1] Also see Chapter VII, Volume One.

VOLUME II
FIGURE 1.1

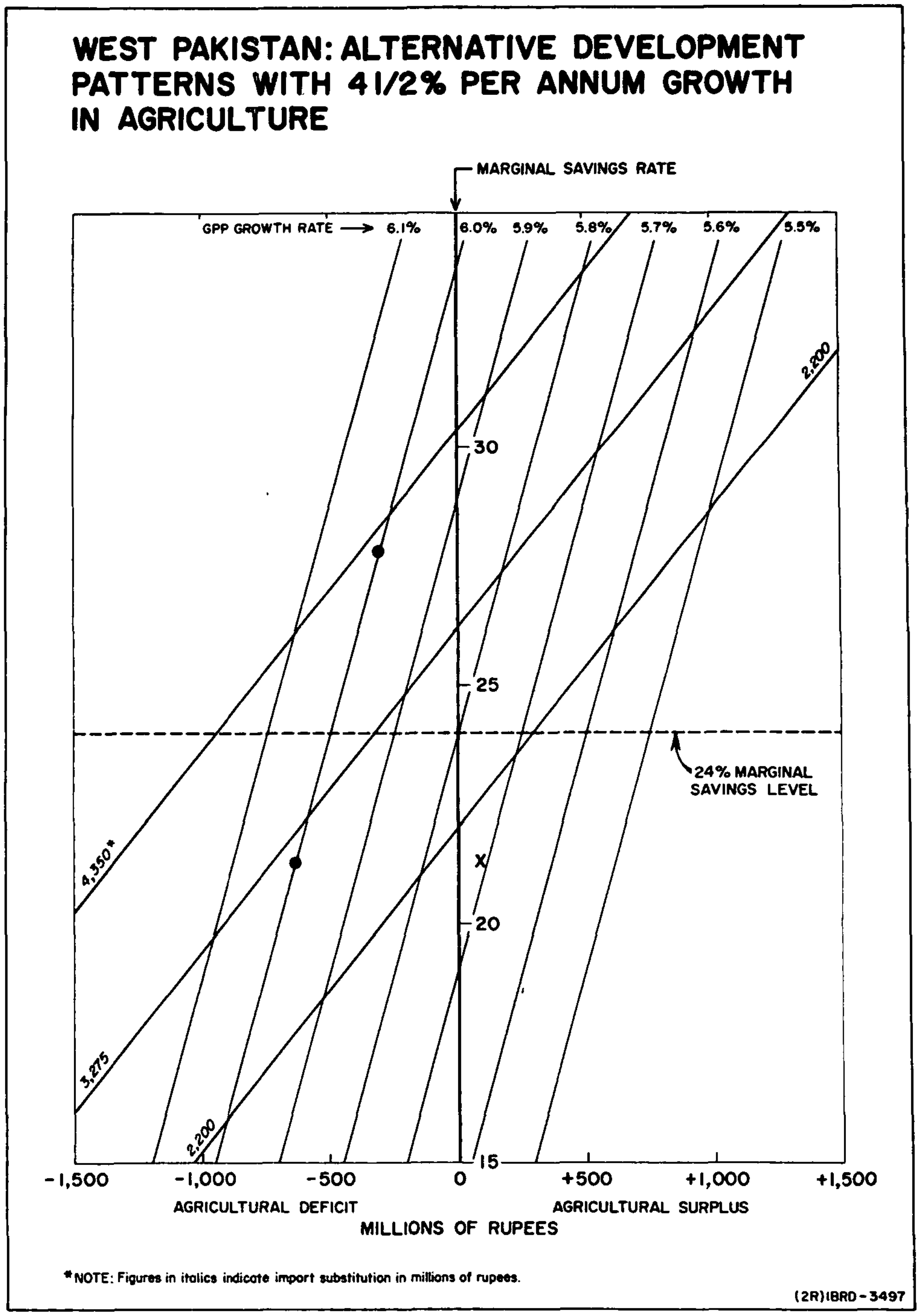


TABLE 1-11

ALTERNATIVE PATTERNS OF GROWTH TO 1975 WITH OVERALL GPP GROWTH RATE OF 6%

	21% Marginal Savings		21% Marginal Savings		28% Marginal Savings	
	IACA Consumption Coeff.		TIMS Consumption Coeff.		IACA Consumption Coeff.	
	Growth Per Annum (%)	Projected 1974/75 (Rs. mill.)	Growth Per Annum (%)	Projected 1974/75 (Rs. mill.)	Growth Per Annum (%)	Projected 1974/75 (Rs. mill.)
Gross Provincial Product by Sector of Origin						
Agriculture[a]	4.4	14,679	4.4	14,679	4.4	14,679
Consumer Goods Manufacturing	6.4	4,665	6.7	4,840	6.2	4,577
Intermediate Goods Manufacturing	12.9	3,168	12.7	3,112	13.5	3,383
Investment Goods Manufacturing	11.2	1,302	10.7	1,243	11.5	1,361
Construction	6.4	1,864	6.4	1,861	6.3	1,857
Transport and Communications	7.4	2,819	6.8	2,648	7.3	2,796
All Other Services	6.0	14,243	6.1	14,357	5.9	14,085
GPP (factor cost)		42,740		42,740		42,738
Indirect Taxes		3,063		3,097		3,078
GPP (market prices)	6.0	45,803	6.0	45,837	6.0	45,816
External Trade						
Exports	7.8	5,571	8.0	5,679	7.8	5,558
Imports	5.5	6,893	5.5	6,945	3.4	5,441
Import Surplus		1,322		1,266		−117
Savings and Investment						
Investment						
Fixed	6.5	9,226	5.8	9,171	6.5	9,291
Stocks						
Consumption	5.6	37,898	5.6	37,931	5.3	36,410
Savings		7,935		7,936		9,436
Import-Substitution		3,121		2,439		4,188

[a] Agricultural growth rate shown here is less than the 4.5 percent projected for 1965–75 because of the lower growth rates actually achieved in 1963–65.

tion to the extent of about Rs. 3,100 million. As noted, the model adjusts the foreign exchange gap to be consistent with the savings-investment gap. The coefficients used by the Study Group result in the investment requirements in 1974/75 being below the level of savings in that year with a 24 percent marginal savings rate, so that there is an accompanying improvement in the balance of payments on current account. The size of this improvement is determined chiefly by the marginal savings rate, and in both the cases described, with a 5.8 percent or a 6 percent growth in total output, it would be of the order of Rs. 600 million.

All the aggregate relationships shown in Figure 1-1 indicate the results of analyses carried out on the assumption that the overall elasticity of demand for directly consumed agricultural products is in the neighborhood of 0.85. This is in line with the calculations made by IACA on the basis of a careful analysis of the elasticity of demand for different crops and it is also consistent with the figures used in several other papers. However, a substantially lower elasticity—of 0.67 —was assumed in the model used in preparation of the Third Five Year; this elasticity was derived from comparison of the estimated input-output tables for Pakistan for 1960/61 and 1964/65. Therefore an alternative set of consumption coefficients was prepared for the Study Group's analysis including a coefficient for directly consumed agricultural products based on this lower elasticity. The results of the analysis using this coefficient were strikingly different from those derived above. Again assuming a 24 percent marginal savings rate as assumed above, the 6 percent growth rate would then be consistent with an agricultural surplus of Rs. 200 million, instead of a deficit of Rs. 500 million, and import substitution in the order of Rs. 2,400 million instead of Rs. 3,100 million. In other words, the change in the elasticity of demand for agricultural products made a difference of about Rs. 700 million in terms of agricultural surplus deficit.

The feasibility of these alternative growth rates under the different conditions assumed depends to a considerable extent on the feasibility of the import substitution implied, and it was partly with a view to helping answer this question that Tables 1-10 and 1-11 were prepared. Table 1-10 represents a conversion of the Perspective Plan projections shown in Tables 1-7 and 1-8 into 1962/63 prices in a form appropriate for comparison with the results of the input-output projection analyses. Table 1-11 shows the results of analyses performed assuming 6 percent growth rate in GPP and a range of savings rates spanning the Perspective Plan's 24 percent. The three cases chosen correspond to the specific points marked in the Figure, the two marked with circles being cases of 6 percent growth with the IACA consumption coefficient for agricultural products, and the one marked with a cross being a case of 6 percent growth using the elasticity of demand for agricultural products which was employed in the preparation of the economic plan. The amounts of import substitution required, according to the model, under the different sets of conditions are shown at the bottom of Table 1-11. With a 21 percent marginal savings rate, for instance, and assuming the IACA coefficient for the demand of agricultural products, the amount of import substitution required is about Rs. 3,100 million or more than 50 percent of the projected increase in output over the 12-year period in the sectors where the import substitution is assumed to occur: consumer goods, intermediate goods and investment goods manufacturing. However, inspection of the growth rates for these sectors in the upper part of Table 1-11, growth rates derived on the assumption that the necessary import substitution will be undertaken, suggests that this amount of import substitution may well be reasonable. Most of the import substitution is assumed to take place in the intermediate goods sector and it suffices to raise the growth rate in that sector to a level comparable with that projected in the Perspective Plan. In all the projections in Table 1-11 the consumer goods manufacturing industry grows about twice as fast as suggested by the Plan. It would appear that the amount of import substitution required to obtain a 6 percent overall growth rate, with 4.5 percent in agriculture, may be feasible. Within the context of the interrelationships specified in the model attainment of the current account improvement projected by the Perspective Plan (see Table 1-10) would require a further improvement in the marginal savings rate and a still larger amount of import substitution.

Financial Requirements

A second major problem which the Study Group wished to investigate was the relationship between the financial requirements of the programs proposed for the development of water, power and agriculture, Plan allocations and total investment. Table 1-12 shows the financial requirements of the various programs, as

TABLE 1-12
FINANCIAL REQUIREMENTS OF PROPOSED PUBLIC SECTOR PROGRAMS BY PLAN PERIODS[a]
(Rs. million)

Third Plan Period		Fourth Plan Period	
Agriculture			
Fertilizer Subsidies	500	Fertilizer Subsidies	700
Plant Protection Subsidies	300	Plant Protection Subsidies	500
Extension and Research	180	Extension and Research	260
Mechanization	214	Mechanization, Forestry, Others, etc.	2,835
Soil Conservation	105		
Animal Husbandry	112		4,295
Colonization	117	Capital Liability for Credit	350
Forestry and Fisheries	304		
Others	364		4,645
	2,196		
Capital Liability for Credit	178		
	2,374		
Irrigation and Drainage			
Ongoing Public Tubewell Projects	873	Ongoing Public Tubewell Projects	118
New Public Tubewell Projects	286	New Public Tubewell Projects	975
Canal Remodeling & Other Irrigation	600	Initial Work on Further Wells	315
Surface Drainage	373	Canal Remodeling & Other Irrigation	402
Tile Drainage	39	Surface Drainage	527
Investigations	191	Tile Drainage	184
Flood Protection	74	Investigations	240
Miscellaneous	25	Flood Protection	75
	2,461		2,836
Surface Water Storage			
Raised Chasma	85	Raised Chasma	31
Tarbela	1,793	Tarbela	2,065
Investigations	38	Sehwan-Manchar	22
		Investigations	77
	1,916		
			2,195
Electric Power			
Generating Units Completed or Under Construction	356	Proposed New Generating Units	1,017
Proposed New Units	697	Transmission Lines	525
Transmission Lines	590	Distribution Lines & Connections, etc	1,890
Distribution Lines & Connections, etc.	1,180	General	36
General	26		3,468
	2,849		

[a] Including taxes and duties and interest during construction at 6 percent per annum except on Tarbela.

TABLE 1-13
COMPARISON BETWEEN PUBLIC SECTOR COSTS OF PROPOSED PROGRAMS AND THIRD PLAN ALLOCATIONS
(Rs. million)

	Third Plan, Revised	Proposed Program
Agriculture	1,816	2,374
Electric Power	2,176	2,849
Irrigation and Drainage	2,211	2,461
Surface Storage (excl. Tarbela)		123
Subtotal	6,203	7,807
Tarbela Dam	—	1,793
Total		9,600

estimated by the Study Group, including interest during construction at 6 percent where appropriate, except on Tarbela Dam. Table 1-13 compares these financial requirements for the Third Plan period with the allocations under the Third Plan itself, as revised in December, 1966 and shown in Table 1-6 above. The table shows that the costs of the programs proposed for each sector are somewhat above those provided for in the revised Third Plan. The allocations to agriculture, water and power in the revised Plan represent about 43 percent of total public development expenditures—somewhat less than the share allocated to these sectors in previous Plans. The combined costs of the proposed programs, excluding the costs of Tarbela for which no financial provision was made in the Third Plan documents, would represent about 54 percent of total public development expenditures as now projected.

Table 1-13 shows that the largest difference between expenditure proposed and Plan allocations occurs in the electric power sector, despite the fact that the revised Plan increased the allocation to power by some Rs. 250 million. The Study Group's estimate for the costs of electric power facilities does include about Rs. 115 million for Mangla Units 1, 2 and 3 which may not be covered under the Plan allocation, but even with deduction of this amount the difference between the figures clearly remains large. The shortfall in the planned allocations for expenditures on agriculture appears large; the Study Group's figure corresponds closely to that in the original Third Plan document which was reduced in the revision of the Plan largely by allowing for lower subsidies on fertilizer, plant protection and mechanization. In the revision of the Plan, the crop production targets were not reduced, and targets for fertilizer absorption and production of food grains were in fact increased. Some reduction in the fertilizer subsidy may be possible without having a serious effect on the absorption of fertilizer but, as discussed in Volume Two, the Study Group believes that the subsidies on agricultural inputs will continue to play a very important role in promoting their use.

The above discussion relates only to public sector expenditures, but the Study Group believes that private investment in the sectors with which it is concerned, and especially in agriculture and irrigation, will play an increasingly important role. Very little information is available regarding past private investment in agriculture and irrigation, but what there is (see page 53 of this paper) suggests that it may have been running around Rs. 300 million per annum. The Study Group has adopted estimates of private investment in agriculture during the Third Plan period based on those given in the Third Plan document and estimates of private investment in irrigation based on the IACA projection of private tubewell growth. As pointed out in Volume II, these estimates may be on the low side, since it may be possible to reach a higher rate of achievement in private tubewell installations and since the Study Group believes that in the long term it should be possible to reach a rate of private investment in agriculture of around 10 percent of gross value added; at Rs. 300 million now, it would represent only some 3-4 percent of present value added in agriculture.

Table 1-14 brings together the various figures available on past investment in agriculture, irrigation and power, past total investment in West Pakistan, future total investment as implied by the Perspective Plan projections in Table 1-7 and the Study Group's projections of future investment in agriculture, irrigation and power. The figures in parentheses represent percentages of Total Plan Investment in each five year plan period. The table suggests that execution of the programs proposed will require devotion of a markedly higher proportion of total investment to the sectors concerned than has occurred in the past. The increases would occur in all sectors, but they would be particularly substantial in public investment in agriculture and electric power; surface storage works, mainly Tarbela, would represent about 6.5 percent of total investment, as projected in the Perspective Plan, over the Third and Fourth Plan periods, and part of this investment would be attributable to the irrigation sector, part to electric power.

The rather high ratios between proposed investments and total investment as projected in the Perspective Plan raises a question as to whether the projections of investment in the Perspective Plan may not be somewhat on the low side. The Study Group did find that the capital-output ratio in agriculture implied by its projections was higher than might be expected on the basis of past experience. For instance, the ratio between total investment in irrigation and agriculture over the Second Plan period and the increase in output over that period has been estimated by the Planning Commission at about 1:9. The Study Group found that the comparable ratios implied by its program and assuming a rate of growth in agricul-

TABLE 1-14
INVESTMENT IN AGRICULTURE, IRRIGATION AND POWER, 1960–75
(Rs. million[a])

	Second Plan (est. actual)	Third Plan[b] (projected)	Fourth Plan[b] (projected)
Private—Agriculture Irrigation	1,500 (7.1)	2,330 (8.5)	4,120(11.0)
Public—Agriculture	625 (3.0)	1,640 (6.0)	3,200 (8.6)
Irrigation	1,658 (7.9)	2,461 (9.0)	2,836 (7.6)
Surface Storage	—	1,916 (7.0)	2,195 (5.9)
Power	1,194 (5.7)	2,849(10.5)	3,468 (9.3)
Total	4,977(23.7)	11,196(41.0)	15,819(42.4)
Indus Basin Works	2,910(13.9)	3,500(16.7)	—
Total Plan Investment	20,973	27,250	37,300

[a] Current prices for the Second Plan period and 1964/65 prices for Third and Fourth Plans.
[b] Investment in agriculture, irrigation and power as projected by the Study Group.

TABLE 1-15
MODEL PROJECTION OF INVESTMENT REQUIRED FOR
SIX PERCENT GROWTH IN GPP
(Rs. millions, 1964/65 prices)

	Third Plan	Fourth Plan
Total Investment	31,175	43,050
Proposed Programs	11,196	15,819
Proposed as % of Total	36%	36.7%

ture of 4:5 percent would be about 2:7 for the Third Plan period and 3:8 for the Fourth Plan period. Part of this large increase was of course attributable to the heavy expenditures that would be made in these periods for construction of Tarbela. Excluding the costs of Tarbela Dam the capital output ratios would be about 2:3 and 2:9 for the two periods respectively. The higher capital-output ratios, based on inclusion of Tarbela in the capital expenditure base, were used in the projection model. The amounts of investment that the model showed to be necessary in 1975 to sustain a 6 percent growth rate in GPP were somewhat above those implied by the Perspective Plan, as comparison of Tables 1-10 and 1-11 above makes clear. From the level of investment projected for 1975 it was possible to infer back the amount of investment required in the intervening plan periods. Table 1-15 compares the results, converted into 1964/65 prices, with the estimates of total investment in water, power and agriculture shown above. These estimates suggest that investment in agriculture, irrigation and power would represent a lower proportion of total investment than implied by Table 1-14; nevertheless there would still be a substantial increase between the Second and subsequent Plan periods in the proportion of total investment required for these sectors.

THE FINANCING OF INVESTMENT

The model projections made by the Study Group suggested that with a marginal savings rate of the order of 24 percent and provided that the requisite amount of import substitution could be undertaken to align the foreign exchange gap with the domestic resources gap, then it would be possible by 1974/75 to finance the projected investment requirements from domestic saving.

Policies will be required to mobilize savings and to direct them towards the sectors where they are required; this is particularly true of rural private saving. Very little is known about the extent of private saving, but it has been thought for some time that substantial transfers of private savings were being made out of the agricultural sector. This, of course, is not necessarily undesirable; one of the important contributions that the agricultural sector has made to economic development in many countries is provision of savings to finance industrialization. Recently, thanks to the work of the Central Statistical Office and the Pakistan Institute of Development Economics, some better estimates of private savings in West Pakistan have become available.[1] Table 1-16 shows some of the results of their work. These figures indicate that nearly one-half of rural incomes are derived directly from agriculture, and since a portion of the "Other" classification may well include some

[1] Asbjorn Bergan, Personal Income Distribution and Personal Savings, 1963/64 (Pakistan Institute of Development Economics, December 1966).

TABLE 1-16
ESTIMATED PERSONAL INCOME AND SAVINGS, 1963/64
(Rs. million)

	Total Personal Income	Sources of Income: Self-employment, Agriculture	Wages, Salaries	Rent, Interest	Other	Personal Savings
Rural	14,560	7,164	2,199	713	4,484	1,395
Urban	5,680	233	3,158	329	1,960	381
Total	20,240	7,397	5,357	1,042	6,444	1,776

agricultural income, it is likely that incomes from agriculture account for somewhat more than half the rural total. The table also shows that personal savings (i.e. savings of individuals, exclusive of corporate savings) in rural areas account for nearly 80 percent of total personal savings, whereas rural personal incomes account for only about 70 percent of total personal incomes. If it is assumed that the same proportion is saved out of agricultural incomes as out of other rural incomes, then savings from direct agricultural income may be in the order of Rs. 700 million. Private investment in agriculture has been estimated at about Rs. 300 million per annum in recent years, as pointed out above; some Rs. 100 million should be added to cover investment in farm dwellings. These figures suggest that substantial transfers of savings out of agriculture—perhaps of the order of Rs. 300 million per year—have been taking place and they also suggest that, if appropriate incentive policies are adopted, farmers should be quite capable of reinvesting in agriculture the amounts projected in Table 1-14.

Much greater difficulty may be encountered in generating sufficient Government revenues to finance the large public programs for water and power development proposed in this report. It is not only a question of the funds required for construction of the proposed projects, but also of those needed for operating and maintaining them in such a way as to derive maximum benefit from them. Shortage of budgetary rupee resources has severely hampered the development effort in recent years. The execution of projects has frequently been held up for lack of rupee funds and some critically important services like education or maintenance of infrastructure works like the irrigation system, which depend relatively little on foreign exchange, have suffered severely from lack of funds. There appears to

TABLE 1-17
CURRENT EXPENDITURES FOR AGRICULTURE AND IRRIGATION DEVELOPMENT PROGRAM
(Rs. million)

	1965	1970	1975
Agriculture Department	36	77	231
Land and Water Development Board	10	28	60
Irrigation Department Establishment	36	54	81
Irrigation System Maintenance	138	244	386
	220	403	758

have been a tendency at some points to initiate more new projects than could be financed without encroaching on the allocations required for completion of ongoing projects and for operation of completed projects. With the major economic progress that is being achieved in West Pakistan requirements for current operational expenditures inevitably increase rapidly. An instance of this is provided by IACA who projected an increase in the current expenditure of the departments responsible for the Irrigation and Agriculture Development Program at a rate above 13 percent per annum, as illustrated in Table 1-17. The Third Five Year Plan document projects an increase in current Government expenditure of about 7 percent per annum. This may be on the low side if full benefit is to be derived from the human and material capital resources which Pakistan has already built up.

Thus, there will be a large need for increased Government revenues to cover both the capital and the current costs of the programs proposed. Various suggestions have been made at different points in the report regarding means of raising additional revenues. At present the agricultural sector, despite its size, makes a very small contribution to Government revenues. Table 1-18 summarizes the available data about this contribution. The chief means of raising funds from agriculture is the Land Revenue, which yielded about Rs. 160 million in 1964/65. It appears that there are considerable difficulties in raising this tax because reassessments are made only at long intervals of 30-40 years and the maximum increase possible at a reassessment is only about 25 percent. The other important means of raising revenue from agriculture is the water rate—assessed in relation to the area and type of the matured crop by the Irrigation Department which maintains its own revenue staff. The net contribution from this source (after meeting the administrative costs of the Irrigation Department) appears to have been about one-third or less of the contribution from Land Revenue. The other taxes on agriculture yield relatively small amounts. The export duty on cotton has been greatly reduced because, although it was an important revenue earner, it was inhibiting the growth of exports. Forest Revenues yield about Rs. 30 million a year. There is also an Agricultural Income Tax but it is paid by only about 12,000 landowners, being confined to those who pay Rs. 250 or more Land Revenue or have land in

TABLE 1-18
CONTRIBUTION OF AGRICULTURE TO GOVERNMENT REVENUES
(Rs. million)

Revenues	1960/61	1961/62	1962/63	1963/64	1964/65
Land Revenue	134	116	145	153	163
Water Charges (net)	108	100	51	36	57
Cotton Export Tax	20	18	28	17	7
Forest Revenues	n.a.	n.a.	27	33	33
Agricultural Income Tax	n.a.	n.a.	3	3	3
Total	262	234	254	242	263
Subsidies to Agriculture					
Fertilizer	19	23	13	52	62
Plant Protection	14	11	21	29	26
Total	33	34	34	81	88
Net Revenues	229	200	220	161	175

excess of 100 acres. One other tax which is incurred by farmers is the local octroi of a few paisa per maund paid on agricultural products taken into town for sale; this tax is a factor in municipal public finance but no information is available on the amount collected. While total revenues from agriculture appear to have remained roughly stable at about Rs. 250 million per annum through the Second Plan period, subsidies to agriculture have been increasing as indicated by the lower portion of Table 1-18.

Comparison of the figures in Table 1-18 with the estimates of sectoral value added suggests that net revenues from agriculture may have fallen from about 3 percent of value added in agriculture at the beginning of the Second Plan to about 1.5 percent at the end of the Plan period. Yet the case for increasing taxation on agriculture is not so simple as this bald statement would imply. It is true that the tax burden on agriculture is light, but also the price structure in West Pakistan is less favorable to agriculture than in many other countries; for instance the ratio between weighted average prices for the products of agriculture in West Pakistan and weighted average prices for domestic manufactures appears to be exceptionally low. To place any overall valuation on the burden borne by agriculture in this manner would require detailed consideration of the price structure in relation to the Province's resource endowment and trends of domestic and foreign demand, but there is no doubt that this burden is large. Without more precise data on this matter it would be hard to argue forcefully simply on grounds of equity for a higher level of taxation on agriculture.

The importance of considering the tax burden on agriculture from this broader point of view is underlined by recent experience. A great deal of the success in agriculture during the Second Plan period seems to be attributable to a sharp improvement in prices for agricultural products relative to those of other goods in the late 1950's and early 1960's, as pointed out in Volume Two. The more favorable price structure made it increasingly attractive to invest in agriculture. The improvement of the price situation faced by the farmer occurred in several ways. Partly it was a matter of gradual reduction in the prices of manufactured goods as the domestic industrial base expanded and competition increased. There were also a number of important shifts in Government policy. The liberalization of imports increased the availability of several important inputs to agriculture. The establishment in 1960 of a buffer-stock in wheat, based on PL 480 supplies, helped to secure a more stable seasonal price pattern for wheat with average prices to the farmer somewhat above those typical in the past when the Government had enforced sale to itself in all surplus areas at less than market prices. The major crop which showed the sharpest production increases during the Second Plan, sugarcane, benefited from a highly favorable Government policy and a heavy duty on imports which raised domestic prices substantially above world market prices. The very changes in taxes and subsidies which were referred to above in connection with the fall in net revenues from agriculture were also important aspects of the improvement in the price situation. The reduction in the export tax on cotton served to raise the effective exchange rate for raw cotton exports from Rs. 3.60 in 1958 to something very close to the official Rs. 4.76 in 1964. The evidence is that these increases in exporters' earnings were to a large extent passed to the farmer and the harvest price of cotton was increased. Production of raw cotton rose slightly from less than 400,000 tons of lint equivalent in 1959/60 to more than 400,000 tons in

1965. The subsidy provided on fertilizer also played an important promotional role, as discussed fully in Volume Two.

Thus it would appear that the Government's need for increased revenue from agriculture should be met by very carefully selected measures which do not destroy the system of incentives built up in recent years. Indiscriminate increase in taxation on agriculture might merely serve to reduce private investment in agriculture and hence increase the need for public investment, exacerbating rather than alleviating the public finance problem. New inputs will continue to need subsidization until there is such a widespread appreciation of their value that a gradual increase in price to the farmer can be accomplished without deterring growth in the use of them; it is not clear that this point has yet been fully reached for either fertilizer or plant protection materials. The value of water, on the other hand, is very widely appreciated and the Study Group believes that there is a strong case for gradual increases in water charges. Such increases could not only make a sizable contribution to the financial effort required to meet the costs of the development program but could also improve the usage of the water available. The Second Plan pointed out that "a large subsidy has been implicit in the provision of water" for irrigation: water rates were increased, but they still seem to be low by comparison with the costs of making water available and even lower by comparison with the benefits that can be derived from water.

The Growth of Agricultural Employment

Another aspect of the proposed program for agricultural development that the Study Group was concerned to elucidate was the contribution it might make to achieving the employment objective of the Perspective Plan. Labor force data are sparse in West Pakistan and estimates of employment and of employment trends are based on rather shaky foundations. The Planning Commission estimates that there are at least 2.5 million man-years of working ability which go unused each year. The extent to which this waste of resources takes the form of seasonal unemployment is uncertain. The evidence is that much of it is more long-term unemployment. The extremely low level of industrial wages in West Pakistan has been widely remarked.[1] As regards agricultural employment the Watercourse Studies carried out by IACA revealed no shortages of labor even at times of peak labor requirements except in a few isolated instances. In general, it was found that there was ample scope within the farmer's family for carrying out prospective increases in cultivation work required.

The Planning Commission has estimated agricultural employment in 1964/65 at about 7.6 million people, meaning 7.6 million man-years of full employment. About 25 percent of this employment, or 1.9 million man-years, was believed attributable to livestock activities and the remainder to cultivation of crops. The estimate of employment provided by crops was based on the assumption that about 395 hours are required per cropped acre per year; a man-year was assumed for this purpose to have 2,600 hours.

The Study Group's agricultural consultants gave considerable attention to employment aspects of agriculture in their Watercourse Studies, and the evidence they

[1] See for example, in the World Bank Report, "The Industrial Development of Pakistan June 7, 1966."

TABLE 1-19
WEST PAKISTAN: EMPLOYMENT ON CROPS, 1965

	Cropped Acreage (mill. acres)	Man-hours per acre	Million Man-hours (1 × 2)
Wheat	12.80	150	1,920
Rice	3.52	174	613
Maize, Millet	5.18	150	777
Grain	2.92	80	234
Pulses	1.22	100	122
Oilseeds	1.77	105	186
Sugarcane	1.21	1,185	1,434
Fruit	0.30	750	225
Vegetables	0.11	1,250	138
Other Food Crops	0.22	75	17
Cotton	3.72	117	435
Tobacco	0.025	500	13
Fodder	6.19	400	2,476
	39.19		8,590

gathered suggested that an allowance of 395 hours of work per cropped acre per year is on the high side. Table 1-19 is based on the Watercourse Studies and other information gathered by the consultants. The figures in the central column for the major crops represent the average number of man-hours actually shown by the Watercourse Studies to be devoted to the respective crops. Figures for the minor crops are estimates. All the man-hour requirement figures relate to irrigated acres, so that weighting them with total acreage, both irrigated and nonirrigated may lead to some exaggeration of the average number of hours required per cropped acre. This weighted average works out at 220 hours. In the Watercourse Studies, figures were also gathered on the maximum number of hours devoted to various crops; the maximum was not very much larger than the average for most crops but for cotton it was nearly 30 percent higher. On a weighted average basis the maximum was about 110 percent of the average. The maximum represented the most advanced practice at present, and it was assumed that as the standard of farming improved the average number of hours devoted to an acre of crops would increase to this level and then beyond it eventually reaching 140 percent of the current average by the reference year 2000.

These two estimates of the amount of time devoted to an average acre of crops are probably not made on the same basis. The Planning Commission's figure should include allowance, for instance, for travel to and from the fields, which is probably not covered by the IACA figure. Appropriate allowances for these aspects of farm work might raise the average hours per cropped acre to somewhere in the neighborhood of 300.

For purposes of projecting employment in agriculture, the Planning Commission makes the following assumptions: Employment on crops increases proportionately with acreage; the employment elasticity with respect to yield is 0.3, i.e. when yield per acre increases 10 percent, employment increases 3 percent; and the employment elasticity with respect to livestock is equal to 0.6. These assumptions do not appear inconsistent with the evidence gathered by IACA. However, some allowance has to be made for increasing mechanization of farming. IACA projected farm-mechanization in terms of full mechanization units, and they projected that by 1975 the degree of mechanization attained should be equivalent to 10 percent of the farm area fully mechanized; by 1985 the level would be 25 percent. In practice farmers would likely mechanize their operations gradually, so that more than 10 percent of the farm area might be partially mechanized by 1975, but the projection in terms of area fully mechanized is useful for calculating costs and labor-implications. IACA's estimates imply that the labor requirement of a fully mechanized farm would be about 65 percent of that of an unmechanized farm.

On the basis of these various assumptions and making allowance for the projected rate of farm-mechanization the Study Group has prepared some estimates of the employment that may be available in agriculture if the production grows at the rates projected in Volume Two of the Report. The starting point of the projection is 6.6 million man-years, representing the Planning Commission's figure for employment in the livestock together with a figure for employment on crops derived on the assumption that about 300 man-hours are required per cropped acre. Table 1-21 shows the projected growth in agriculture and the employment estimates derived therefrom. The estimates of the total labor force given at the bottom of the table is based on the assumption that the labor force was in 1965, and will remain, about 31.6 percent of total population. This is the Planning Commission's figure. The underlying population projection, which is slightly above that used by the Planning Commission, is shown in Annex 2. Table 1-21 suggests that agricultural employment may increase by about two-thirds between 1965 and 1985, equivalent to an annual rate of growth of 2.5 percent. The proportion of the labor force employed in agriculture would remain little changed. However, it should be borne in mind that these are Provincial average figures and there may be considerable variations in the growth of agricultural employment in different parts of the Province.

TABLE 1–20

WEST PAKISTAN: GROSS PROVINCIAL PRODUCT, 1949/50–1964/65

(factor cost in Rs. million at constant 1959/60 prices)

Sector of Origin	1949/50	1950/51	1951/52	1952/53	1953/54	1954/55	1955/56	1956/57	1957/58	1958/59	1959/60	1960/61	1961/62	1962/63	1963/64	1964/65
Agriculture	6,595	6,768	6,155	6,166	7,005	6,948	7,093	7,254	7,393	7,689	7,711	7,695	8,171	8,597	8,813	9,276
a) Crops	4,250	4,368	3,697	3,653	4,432	4,320	4,405	4,502	4,578	4,822	4,775	4,709	5,127	5,486	5,638	6,018
b) Other	2,345	2,400	2,458	2,513	2,573	2,628	2,687	2,752	2,815	2,867	2,936	2,986	3,044	3,111	3,175	3,258
Mining and Quarrying	27	37	41	42	45	45	50	55	59	64	70	81	86	96	104	116
Manufacturing	1,004	1,095	1,186	1,313	1,495	1,692	1,869	1,975	2,050	2,138	2,192	2,482	2,745	3,009	3,353	3,778
a) Large-scale	320	395	469	580	745	925	1,084	1,172	1,229	1,298	1,333	1,600	1,840	2,080	2,400	2,800
b) Small-scale	684	700	717	733	750	767	785	803	821	840	859	882	905	929	953	978
Construction	179	187	247	262	283	289	323	337	386	459	427	612	596	700	837	921
Electricity, Gas, Water, etc.	27	29	31	30	35	37	43	57	63	66	87	99	99	122	142	173
Transport & Communication	608	645	658	712	754	810	832	866	877	1,051	921	1,023	987	1,086	1,118	1,171
Wholesale & Retail Trade	1,477	1,567	1,575	1,585	1,685	1,777	1,818	1,876	1,939	1,988	2,105	2,198	2,301	2,493	2,746	2,927
Banking and Insurance	39	42	46	50	54	56	68	83	81	92	112	124	134	150	163	179
Ownership of Dwellings	632	649	670	686	704	725	745	769	792	815	837	858	888	916	952	976
Services	955	993	1,033	1,074	1,117	1,162	1,208	1,256	1,307	1,359	1,411	1,478	1,537	1,601	1,665	1,727
Public Admin. and Defense	609	622	706	684	676	692	707	741	733	782	785	792	841	879	960	969
Net factor income from abroad	−18	−18	−11	−13	−27	−4	−20	−17	−4	−10	−17	−15	−18	−38	−47	−47
Gross Provincial Product (factor cost)	12,134	12,616	12,337	12,591	13,826	14,229	14,736	15,252	15,676	16,493	16,641	17,427	18,367	19,611	20,806	22,166

Sources: Government of Pakistan, Final Report of the National Income Commission (November, 1965).

Taufiq M. Khan and A. Bergan, "Measurement of Structural Change in the Pakistan Economy: A Review of the National Income Estimates, 1949/50–1963/64" Pakistan Development Review, Summer 1966.

Supplementary Information, especially on 1964/65 and the growth of large scale manufacturing industry, provided by Pakistan Planning Commission.

TABLE 1-21
ESTIMATE OF EMPLOYMENT IN AGRICULTURE, 1965–85

	1965	1975	1985
Crops			
Cropped Acres (mill.)	40.72	47.84	54.30
GPV of crops per acre (Rs.)	133	184	260
Employment (mill. man-years)	4.7	5.8	6.9
Livestock			
Gross Production Value (Rs. mill.)	3.3	5.6	9.8
Employment (mill. man-years)	1.9	2.7	3.9
Total Agricultural Employment	6.6	8.5	10.8
Total Labor Force	16.2	21.2	28.1
Agriculture as % of total	40.7%	40.1%	38.4%

DETAILS OF THE PROJECTION MODEL

Data for the Model

This section of the paper describes the slight adjustments that the Study Group made to the input-output model used in preparation of Pakistan's Third Five Year Plan and discusses in detail the data which the Study Group prepared for use in the model. The original input-output projection model is described by its author, Wouter Tims, in a paper, "Growth Model for the Pakistan Economy, Macroeconomic Projections for Pakistan's Third Plan" (Planning Commission, Karachi, March 1965). The model contained 98 equations and 105 variables, of which 7 were exogenous. For ease of computation Tims' system of equations was reduced by the Study Group to 84 equations with 92 variables of which 8 were exogenous. Five equations regarding the formation of stocks were omitted because this item is relatively minor and because no data were available regarding stock formation in West Pakistan. The reduction of the system by a further nine equations was carried out by amalgamating some of Tims' definitional equations and omitting the equations explicitly defining value added by sectors. Sectoral value added could still be derived with ease by subsequent manual calculation, subtracting intermediate inputs and imports into each sector, together with indirect taxes on sectoral output from the GVP for each sector; all these items were explicitly presented in the computer printout for the model. The exogenous variables used in the reduced version of the Tims' model numbered one more than he had used because allowance was made for export of services from the Transport and Communication Sector, which did not show up as an independent item in his base-year input-output table.

The 92 variables used by the Study Group are shown in Table 1-22, with the exception of E_8 and S. E_8 stands for import substitution, which is a critical item in the model; it indicates the value of goods which, according to the adjustment mechanism built into the model, must be produced domestically beyond what would otherwise have been the case simply to balance the Domestic Resource (Savings-Investment) Gap and the Foreign Exchange (Exports-Imports) Gap. S (savings) is an exogenous variable.

Apart from the abovementioned slight technical changes in the structure of the model, changes of much greater significance had to be made in the procedures for deriving the coefficients for the model. One of the chief characteristics of the Tims model, as originally formulated, was that it used marginal coefficients derived on the basis of comparison of an estimated actual input-output table for 1960/61 for Pakistan and a 1964/65 input-output table that was part estimated and part projected. For West Pakistan only one input-output table has been prepared—a 70-sector table for 1962/63, prepared by Mr. Ghulam Rasul of the Pakistan Planning Commission. It was therefore not possible to estimate marginal coefficients for West Pakistan in the manner used by Tims for Pakistan as a whole. Only in the case of sectoral imports from abroad did the Study Group have approximate data for two years—1962/63, provided by the Planning Commission, and 1964/65, prepared by the Study Group on the basis of classifications used by the Planning Commission.

For the agricultural sector the Study Group had its own projections of inputs from other sectors, etc., which had been made in the course of the Study, but for most sectors it was necessary to adopt some other procedure for deriving coefficients. The basic approach was to apply the elasticities implict in Tims' coefficients to the base-year 1962/63 coefficients derived from the West Pakistan input-output table. These elasticities are the ratio between the marginal coefficients for Pakistan, calculated on the basis of the change between 1960/61 and 1964/65, and the average coefficient in 1960/61. Tims assumed in effect that the changes which had characterized the years 1960/61—1964/65 would continue to operate over the years 1964/65 to 1969/70. Application of these elasticities to West Pakistan implied two very radical assumptions: (a) that the patterns of change which had characterized Pakistan in 1960/61—1964/65 had also characterized West Pakistan alone and (b) that these patterns of change would continue to be operative, not only to 1970, but to 1975, which was the year to which the Study Group wanted to make projections, consistently with its recommended program for agriculture and power development. These assumptions are clearly indefensible; they were necessitated by the lack of any alternative. Attempts were made to minimize the extent to which the results would be misleading by adjusting the marginal coefficients derived for West Pakistan in light of any other information available qualitative consideration of the relevance of each sectoral datum for Pakistan to the Province of West Pakistan and, in particular, careful comparison between the marginal coefficients derived in this manner, the base-year coefficients for West Pakistan and Tims' marginal coefficients for Pakistan. In most cases where adjustments were made it appeared that the West Pakistan coefficients in 1962/63 may already have been at the extreme end of the range encountered in Pakistan as a whole by 1964/65, so that to multiply the 1962/63 West Pakistan coefficient by the Pakistan elasticity for 1960/61—1964/65 could lead to great exaggeration. Adjustments made were generally in the direction of the base-year coefficient, whether this involved raising or lowering the mechanically derived one.

This technique of applying Pakistan elasticities to West Pakistan base-year data was used particularly for the interindustry coefficients, other than those for inputs

TABLE 1–22
WEST PAKISTAN INPUT-OUTPUT MODEL—SYMBOLS

Origin \ Destination	Agriculture	Consumer Goods Manufacturing	Intermed. Goods Manufacturing	Investment Goods Manufacturing	Construction	Transport and Communications	All Other Services	Total Inter-industry Supply	Consumption	Investment in Fixed Assets	Export of Goods and Services	Total Final Demand	Gross Value of Production
1. Agriculture	x_{11}	x_{12}	x_{13}	x_{14}	x_{15}	—	—	—	c_1	—	e_1	—	X_1
2. Consumer Goods Manufacturing	x_{21}	x_{22}	x_{23}	x_{24}	x_{25}	x_{26}	x_{27}	—	c_2	—	e_2	—	X_2
3. Intermed. Goods Manufacturing	x_{31}	x_{32}	x_{33}	x_{34}	x_{35}	x_{36}	—	—	c_3	—	e_3	—	X_3
4. Investment Goods Manufacturing	x_{41}	x_{42}	x_{43}	x_{44}	x_{45}	x_{46}	—	—	c_4	i_4	e_4	—	X_4
5. Construction	—	—	—	—	—	—	x_{57}	—	c_5	i_5	—	—	X_5
6. Transport and Communications	x_{61}	x_{62}	x_{63}	x_{64}	x_{65}	x_{66}	x_{67}	—	c_6	i_6	e_6	—	X_6
7. All Other Services	x_{71}	x_{72}	x_{73}	x_{74}	x_{75}	x_{76}	x_{77}	—	c_7	i_7	e_7	—	X_7
Total Interindustry Demand	—	—	—	—	—	—	—	—	—	—	—	—	—
Gross Value Added	V_1	V_2	V_3	V_4	V_5	V_6	V_7	—	—	—	—	—	Y
Indirect Taxes (less subsidies)	t_1	t_2	t_3	t_4	t_5	t_6	t_7	—	t_c	t_i	t_e	—	—
Imports of Goods and Services	m_1	m_2	m_3	m_4	m_5	m_6	m_7	—	m_c	m_i	—	—	M
Gross Value of Production	X_1	X_2	X_3	X_4	X_5	X_6	X_7	—	C	I	E	—	—
Investment by Destination	i'_1	$\longleftarrow i'_{2-5} \longrightarrow$				i'_6	i'_7	—	—	—	—	—	—

TABLE 1-23
WEST PAKISTAN INPUT-OUTPUT TABLE 1962/63—TECHNICAL COEFFICIENTS

	Agri-culture	Consumer Goods Manu-facturing	Inter-mediate Goods Manu-facturing	Invest-ment Goods Manu-facturing	Con-struction	Transport and Commu-nications	All Other Services
1. Agriculture	0.1323	0.4049	0.3061	0.1661	0.0219	—	—
2. Consumer Goods Manufacturing	0.0010	0.0371	0.0062	0.0319	0.1133	0.0142	0.0190
3. Intermed. Goods Manufacturing	0.0206	0.0906	0.0968	0.0300	0.1631	0.0637	—
4. Investment Goods Manufacturing	0.0010	0.0036	0.0058	0.0188	0.0087	0.1216	—
5. Construction	—	—	—	—	—	—	0.0134
6. Transport and Communications	0.0152	0.0226	0.0547	0.0347	0.2054	0.0321	0.0098
7. All Other Services	0.1065	0.0845	0.0922	0.0610	0.0113	0.0274	0.0008
Total Interindustry Demands	—	—	—	—	—	—	—
Gross Value Added	—	—	—	—	—	—	—
Indirect Taxes (less subsidies)	−0.0008	0.0594	0.0808	0.0779	0.0255	0.0311	0.0003
Imports of Goods and Services	0.0068	0.0649	0.0687	0.2373	0.1267	0.0768	0.0082
Gross Value of Production							

into agriculture. The resultant equations are presented at the end of this section of the paper. The coefficients which were adjusted are underlined. Comparison of these coefficients with the base-year coefficients for West Pakistan presented in Table 1-23 and with Tims' marginal coefficients for Pakistan, presented in the above mentioned document, will indicate the reasons for the changes made. Changes of greatest significance were found to be necessary in the coefficients for inputs into Transport and Communication and into Investment Goods Industries. Changes of special importance from the point of view of the Study were in the coefficient for inputs from agriculture into consumer goods manufacturing (x_{12})—which was raised from 0.2632 to 0.3000, in order to bring it more into line with Tims' coefficient and to reduce the magnitude of the implied change from the base-year coefficient—and in the coefficient for inputs from agriculture into investment goods industries, which was reduced from 0.2922 to 0.1700 precisely on the above stated grounds that the base-year coefficient for West Pakistan appeared to be very much at the upper end of the range of coefficients relevant to Pakistan at the present time.

Coefficients relating to inputs into agriculture were derived directly from the work of the Study Group and its consultants, as presented in Volume Two (Annex 10). The elasticities implied by these figures are shown in Table 1-24. Deliveries from agriculture into agriculture—mainly fodder and seed—appear likely to grow

TABLE 1-24
ELASTICITY OF INTERSECTORAL DELIVERIES TO AGRICULTURE, 1962/63

Sector of Origin	Elasticity
Agriculture	0.47
Consumer Goods Manufacturing	1.30
Intermediate Goods Manufacturing	6.80
Capital Goods Manufacturing	3.50
Transport and Communication	2.10
All Other Services	1.60

slowly relative to total agricultural production. Deliveries from the intermediate goods sector—fertilizer, cotton-seed, electricity, fuel, plant protection equipment and insecticides—are likely to grow extremely rapidly. Deliveries from the capital goods sector will be mainly spares for tubewells and farm machinery.

As regards consumption expenditures (Equations 40–46) Tims' elasticities were used for all sectors except consumption of other services which was adjusted very slightly upward and consumption of agricultural products for which the elasticity was raised substantially to bring it into line with the projections of demand for agricultural products made by IACA, on the basis of demand elasticities for individual crops. IACA chose demand elasticities for agricultural products mainly on the basis of FAO's estimates for the whole of Pakistan, as given in "Agricultural Commodities—Projections for 1970" (1962). FAO's estimates were in turn based on international comparative study. Table 1-25 gives the main details of the IACA assessment of demand for agricultural products. It also shows the farm-gate prices which were used by the Study Group as weights for each crop in the derivation of an aggregate demand elasticity for agricultural products. To obtain an indication of the growth in demand for unprocessed agricultural products (i.e. agricultural products which would enter into the input-output table as direct consumption rather than as an input into another sector) per capita consumption of all the above crops except for cotton and fats and oils was multiplied by farm-gate prices and projected to 1975 according to the expenditure elasticities shown, for various different assumptions regarding growth of incomes and savings. The results were added to give total per capita consumption of food products and these aggregates were multiplied by population, assumed at 51.2 million in 1965 and 66 million in 1975, consistently with IACA. On this basis the overall expenditure elasticity of demand worked out at about 0.85.

An expenditure elasticity of demand for agricultural products of 0.85 is very high compared with the 0.67 derived by Tims on the basis of comparison of the 1960/61 and 1964/65 input-output tables. Nevertheless it seemed reasonable

TABLE 1–25

IACA's Projection of Demand for Agricultural Products—Underlying Data

	1965 Per Capita Consumption	Farm-Gate Price	Expenditure Elasticity of Demand
	(kilos/capita)	(Rs./md)	(1965)
Wheat	95.0	13.0	0.55
Other grains	13.0	11.0	
Rice	17.0	12.0	
Sugar	19.0	47.7	0.70
Pulses and gram	14.5	17.0	0.30
Potatoes	2.2	10.0	0.50
Vegetables	17.0	11.0	1.00
Fruit	13.0	11.0	1.00
Fats and oils	3.4	78.0	1.30
Milk, milk products	117.0	16.5	1.00
Meat	7.7	62.0	1.50
Eggs	0.3	3.4	2.00
Fish	1.1	80.0	1.40
Cotton (lint)[a]	2.0	90.0	1.00

[a] Two kilos of cotton lint equivalent to 13 yards of cloth.

TABLE 1-26
ALTERNATIVE SETS OF CONSUMPTION COEFFICIENTS

	West Pakistan 1962/63	IACA Agriculture		Tims Agriculture	
		Elasticity	Coefficient	Elasticity	Coefficient
Agriculture	0.2771	0.85	0.2355	0.67	0.1857
Consumer Goods Manufacturing	0.3970	1.15	0.4566	1.28	0.5092
Intermediate Goods Manufacturing	0.0059	1.75	0.0103	3.49	0.0206
Capital Goods Manufacturing	0.0194	1.19	0.0230	1.19	0.0230
Construction	0.0130	0.70	0.0091	0.70	0.0091
Transport and Communications	0.0151	2.78	0.0420	1.75	0.0264
All Other Services	0.2139	0.64	0.1365	0.65	0.1390
Indirect Taxes	0.0098	1.00	0.0090	1.00	0.0098
Imports	0.0488	1.58	0.0772	1.58	0.0772
	1.0000		1.0000		1.0000

when examined from the standpoint of the experience of other countries. It appeared to be even still somewhat on the low side compared with the overall elasticity of demand for farm products derived by FAO in their studies referred to above; they estimated the income elasticity of demand for total "farm value" of agricultural product in Pakistan at 0.96. The corresponding expenditure elasticity would have been slightly higher. However, this estimate was believed applicable to the situation in 1957–59 and, since demand elasticities for agricultural products tend to decline with income-growth, it would probably be correct to adjust it downward for application to the situation in 1964/65. Besides the FAO estimate an alternative was also available in a paper by Tims, "Industrial Growth during the Third Plan" (Planning Commission, Karachi, July 1965). There Tims considers FAO and other data and concludes that the income elasticity of demand for directly consumed agricultural products must now be 0.85; this would correspond to an expenditure elasticity of demand of about 0.94; assuming a 10 percent average savings rate and 20 percent marginal savings rate.

The model was run chiefly with the consumption coefficients adjusted on the basis of the IACA data for specific crops, but some tests were also made with consumption coefficient based on an elasticity of demand for directly consumed agricultural products identical with that originally used by Tims. Table 1-26 shows the base-year coefficients for West Pakistan and the two sets of coefficients used, with their corresponding elasticities. The table includes elasticities of demand for imports and for expenditures on indirect taxes; elasticities used for these items were those derived by Tims for Pakistan.

In the formulation of the equations for investment by sectors of origin and destination particular attention had to be paid to the much longer time span of projection required for these studies compared with that used by Tims in projecting for Pakistan. Tims had calculated a base-year investment matrix for Pakistan and then made some adjustments to allow for increased production from the domestic investment goods industry substituting for imported investment goods. He raised the coefficient representing domestic deliveries of manufactured investment goods by about one-third, on the assumption that this would be about the maximum that could be expected to be achieved by the domestic investment goods industry by the end of the Third Plan. The domestic construction industry was also assumed to be responsible for a slightly larger share of total investment by 1969/70 than it had been in 1962/63, the base-year for which data were available for this type of analysis. Compensating downward adjustments were made chiefly in imports of investment goods.

For West Pakistan a base-year investment matrix was prepared by the Study Group, but radical adjustments were made to it to allow for growth of the domestic industry responsible for manufacturing machinery and transport equipment. The base-year investment matrix, shown in the upper portion of Table 1-27, was built up on the basis of the detailed West Pakistan input-output table and the data presented in Tables 1-28, 1-29 and 1-30. The resultant matrix differs in significant respects from that prepared by Tims for Pakistan; trade margins show up as an important component in the cost of imported capital goods. The contribution of the domestic capital goods industry to investment in manufacturing industry appears much less significant in the West Pakistan table. For projection of the situation in 1974/75 much use was made of some rough estimates prepared by the Planning Commission on the basis of the Third Five Year Plan and the Perspective Plan. The projected matrix is presented in the bottom portion of Table 1-27, which shows, by comparison with the upper portion, substantial increases in the contributions of the domestic capital goods industry to investment in manufacturing and in transport and communications.

TABLE 1-27
WEST PAKISTAN: INVESTMENT BY ORIGIN AND DESTINATION 1962/63 AND PROJECTED 1974/75
(Rs. million, current prices of 1962/63)

Destination / Origin	Agriculture	Manufacturing, etc.	Transport, Communications	All Other Services	Total
Investment Goods Industry	67	144	75	—	286
Construction	951	426	248	765	2,390
Transport, Communication	6	151	18	—	175
Other services	13	274	32	—	319
Imports (cif)	56	773	160	—	989
Indirect Taxes	8	120	55	—	183
Total	1,101	1,888	588	765	4,342
In % by Columns					
Investment Goods Industry	6.0	7.6	12.8	—	
Construction	86.4	22.6	42.2	100	
Transport, Communication	0.6	8.0	3.0	—	
Other Services	1.1	14.5	5.5	—	
Imports (cif)	5.1	40.9	27.2	—	
Indirect Taxes	0.8	6.4	9.3	—	
In % by Columns, Projected for 1974/75					
Investment Goods Industry	8.0	22.0	40.0	—	
Construction	78.0	27.0	38.0	100	
Transport, Communication	1.0	5.0	2.0	—	
Other Services	1.5	8.0	4.0	—	
Imports (cif)	9.0	30.0	12.0	—	
Indirect Taxes	2.5	8.0	4.0	—	

TABLE 1-28
WEST PAKISTAN: ESTIMATE OF GROSS FIXED INVESTMENT,[a] 1962/63
(Rs. million, current prices)

	Private	Public Authorities	Central Government	Provincial Government	Local Government	Rural Works Program	IBP	Total
Agriculture	392.5	57.7	14.8	28.7	20.4	0.3	2.6	517.0
Irrigation, Wells	113.8	11.0	0.1	4.6	10.3	0.2	—	140.0
Private Tubewells	45.0	—	—	—	—	—	—	45.0
Land Improvement	45.5	37.0	—	10.7	—	—	—	93.2
Afforestation, etc.	—	1.0	1.0	5.0	8.1	—	0.1	15.2
Research Labs, etc.	—	0.7	8.5	2.8	0.1	—	2.5	14.6
Small Implements	13.7	—	—	—	—	—	—	13.7
Farm Dwellings	136.5	5.0	0.1	2.0	—	0.1	—	143.7
Agricultural Machinery	38.0	3.0	5.1	3.6	1.9	—	—	51.6
Buildings								
Nonfarm Residential	309.0	45.0	34.0	16.0	4.3	—	92.4	500.7
Service Buildings	42.5	3.2	41.0	61.4	22.5	67.3	5.9	243.8
Factories	160.5	60.0	0.5	7.0	0.8	0.1	2.0	230.9
Water and Power	—	356.6	59.0	5.8	11.1	0.1	473.1	905.7
Other Construction (including roads, railways)	—	55.5	21.2	161.8	32.5	1.6	6.3	278.9
Vehicles	164.9	23.7	16.6	155.4	0.8	—	12.5	373.9
Nonagricultural Machinery and Equipment	430.2	83.0	6.6	45.0	6.0	—	183.0	753.8
Total	1,499.6	684.7	193.7	481.1	98.4	69.4	777.8	3,804.7

[a] This estimate of Fixed Capital Formation was prepared in 1964 by Dr. J. R. L. van den Elshout ("A Revised Estimate of the Gross Investment in Fixed Capital Assets in Pakistan in 1962–63"—December 18, 1964). The estimate includes nonmonetized investment. The Planning Commission has since revised Elshout's estimate upwards to Rs. 4,410 million, but the detailed breakdown of the new estimate is not available. The difference between the two estimates seems to be mainly accounted for by an upward revision of about Rs. 600 million in the figure for investment in machinery and equipment.

TABLE 1-29
WEST PAKISTAN: ESTIMATED FIXED INVESTMENT, 1960–65
(Rs. million, current prices)

	1959/60[a]	1960/61	1961/62	1962/63	1963/64	1964/65
Construction	1,180	1,983	2,217	2,566	2,883	3,089
Of which:						
Factories, etc.	286	300	392	584	552	551
Other Monetized	583	1,319	1,415	1,530	1,924	2,123
Nonmonetized	296	296	296	296	296	296
Railways	60	68	114	156	111	119
Machinery	670	712	932	1,406	1,346	1,360
Transport	206	329	381	438	525	813
Total Fixed Investment	2,055	3,022	3,528	4,410	4,753	5,260
Of which:						
Indus Basin Works	—	100	210	780	890	930
Total, excluding Indus Basin Works	2,055	2,922	3,318	3,630	3,863	4,330

[a] Years refer to fiscal years: i.e., 1959/60 refers to July 1, 1959 to June 30, 1960.
Source: Government of Pakistan, Planning Commission: "Evaluation of the Second Five-Year Plan (1960–65)," May 1966.

TABLE 1-30
WEST PAKISTAN: IMPORT COMPONENT OF FIXED INVESTMENT, 1960–65
(Rs. million, current prices)

	1960	1961	1962	1963	1964	1965
Construction						
Investment	1.180	1,983	2,217	2,566	2,883	3,089
Cement Imports[a]	10	10	3	5	15	13
Steel Imports[a]	22	46	91	99	105	137
Imports	32	56	94	104	120	150
Import Component (%)	2.7	2.8	4.2	4.1	4.2	4.9
Machinery						
Investment	670	712	932	1,406	1,346	1,360
Imports[a]	391	408	528	853	794	802
Import Component (%)	58.4	57.3	56.7	60.7	59.0	59.0
Transport Equipment						
Investment	206	329	381	438	525	813
Imports[a]	67	126	158	165	198	245
Import Component (%)	32.5	38.3	41.5	37.7	30.5	30.1
Total Fixed Investment						
Investment	2,055	3,022	3,528	4,410	4,753	5,260
Imports[a]	490	590	780	1,122	1.112	1,197
Import Component (%)	23.8	19.5	22.1	25.4	23.4	22.8

[a] As specified here, imported goods are valued cif, but they are of course included in the investment estimates at their total onsite delivered domestic price, including import duties.

Source: Government of Pakistan, Planning Commission: "Evaluation of the Second Five Year Plan (1960–65)," May 1966.

Indirect taxes and subsidies are covered by equations 51 to 60. Most of these equations were derived in the manner described above for the technical interindustry coefficients; but, as indicated by the underlining, many of the coefficients were further adjusted in light of comparison with the marginal coefficients used by Tims for Pakistan and the base-year West Pakistan coefficients shown in Table 1-23. The coefficient for agriculture was derived on the basis of figures presented in Volume Two of this report. The main considerations here are the subsidies that will be provided on fertilizer and plant protection since taxes on agricultural products and on imported inputs into agriculture are likely to remain small by comparison. The subsidy on fertilizer in 1974/75 is projected at about Rs. 280 million, or 30 percent of the total cost of fertilizer in that year, while the subsidy on plant protection would be about 50 percent of the projected total expenditure of Rs. 300 million on this service. Taxes on investment goods were projected in Table 1-27 as a proportion of total investment expenditure by sector of destination. The coefficient for taxes on exports was derived on the basis of the elasticity of 0.57 implicit in Tims' figures; the total yield from export taxes has in fact fallen substantially in recent years with the reduction in the export tax on cotton, the main source of export tax revenue, but the way in which export tax revenues may move in future is hard to predict. It would seem likely to move downward. The export tax item is anyway very small in the overall picture.

The equations regarding imports are important, but they were also quite problematic. The base-year input-output table for West Pakistan shows imports from abroad at Rs. 3,130 million and imports from East Pakistan at Rs. 507 million. Both of these figures are substantially above those indicated by the other trade information available to the Study Group, which is generally based on Central Sta-

TABLE 1-31
WEST PAKISTAN: VISIBLE IMPORTS FROM EAST PAKISTAN BY SECTOR OF DESTINATION
(Rs. million)

	1960/61	1961/62	1962/63	1963/64	1964/65
Agriculture	12	12	18	20	20
Consumer goods manufacturing	94	97	128	135	162
Intermediate goods manufacturing	20	22	22	24	25
Transport and communications	8	13	12	12	17
Trade	20	22	22	24	25
Consumption	179	228	218	293	287
	333	394	420	508	536

tistical Office data; however, these data do not give a complete coverage of visible trade and they do not cover invisibles at all, so that it was necessary to adjust the available data to conform with the magnitudes shown in the input-output table. Table 1-31 shows the available data regarding imports from East Pakistan, classified by the Study Group by sector of destination. The Table shows that imports from East Pakistan have been increasing quite rapidly in recent years. Data in 70-sector West Pakistan input-output table suggested that the main sectors where adjustments should be made to bring the above set of trade figures into line with those in the input-output table were consumer goods manufacturing and consumption imports. Table 1-32 shows the basic data generated regarding foreign imports in 1962/63 and 1964/65 and then the figures for imports from abroad and imports from East Pakistan as finally adjusted to bring them into line with the input-output table data. The increase in total imports (regional and foreign) by sector of destination between 1962/63 and 1964/65 was compared with the increase in

TABLE 1-32
WEST PAKISTAN IMPORTS BY SECTOR OF DESTINATION
(Rs. million)

	Recorded Visible Trade		Adjusted Import Figures			
	1962/63	1964/65	1962/63		1964/65	
			From East Pakistan	From Abroad	From East Pakistan	From Abroad
Agriculture	50	18	18	63	20	24
Consumer Goods Manufacturing	596	1,076	149	471	188	850
Intermediate Goods Manufacturing	177	278	22	151	25	236
Capital Goods Manufacturing	114	214	—	251	—	470
Construction	282	292	—	348	—	362
Transport and Communications	55	102	12	135	17	250
All Other Services	22	39	22	41	25	73
General Industry	228	313	—	—	—	—
Consumption	263	384	280	681	367	811
Investment	983	1,020	—	989	—	1,027
Total	2,770	3,736	503	3,130	642	4,103

TABLE 1-33
IMPORT COEFFICIENTS AND ELASTICITIES

	Tims: Pakistan Imports CIF from Abroad		W. Pakistan: Imports CIF from Abroad and from East Pakistan			
	Elasticity[a]	Adopted Marginal Coefficient[b]	1962/63 Coefficient[c]	Marginal Coefficient[d] 1962/63–64/65	Adopted Coefficient	Implied Elasticity
Intermediate Goods						
for Agriculture	2.50	0.0155	0.0068	−0.0379	0.0125	1.84
Consumer Goods	2.36	0.1019	0.0649	0.3367	0.1207	1.86
Intermediate Goods	1.10	0.1044	0.0687	0.0625	0.0756	1.10
Capital Goods	.73	0.1573	0.2373	0.3955	0.2300	0.97
Construction	1.11	0.1721	0.1267	0.0159	0.1407	1.11
Transport & Comm.	1.45	0.1065	0.0768	0.7895	0.1114	1.45
Services	2.00	0.0054	0.0082	0.0391	0.0082	1.00
Consumer Goods	1.58	0.0697	0.0487	0.0919	0.0772	1.58

[a] I.e., marginal import coefficient, as estimated for 1960/61–1964/65 by Tims at the time the model was being prepared, divided by the average import coefficient in 1962/63. See Pakistan Planning Commission, "Growth Model for the Pakistan Economy," Macroeconomic Projections for Pakistan's Third Plan (Karachi, March 1965).

[b] I.e., the factor by which the increase in gross production in each sector has to be multiplied in order to derive its estimated import requirements.

[c] Derived from base-year input-output table for West Pakistan.

[d] Estimated on basis of trade classification, provided by the Planning Commission for West Pakistan for 1962/63, and an allocation by the Study Group of 1964/65 trade on the basis of the same classification.

Gross Value of Output by sector over the same period, estimated on the assumption that sectoral Gross Value of Output grew at the same rates as sectoral Gross Value Added. The results were not very meaningful as indicated by the column "Marginal Coefficient 1962/63–1964/65" under West Pakistan on the right-hand side of Table 1-33. Therefore it was decided generally to adopt the elasticities derived for foreign imports into the whole of Pakistan, as derived by Tims and presented on the left-hand side of Table 1-33, for calculating the coefficients for most sectors; however, the results were adjusted in several cases on the basis of the base-year West Pakistan coefficients and the marginal 1962/63–1964/65 coefficients derived in the manner described above. Imports into agriculture were projected separately on the basis of information provided in Volume Two of this Report; since it was assumed that by 1975 all fertilizer requirements would be met from domestic production, the main imports into agriculture by 1975 would be some pesticides which would not be produced domestically by then and various minor items such as inputs for the livestock sector and seed and certain services. Table 1-33 shows that the resultant elasticity is low compared with Tims' elasticity for imports into agriculture. The penultimate column of the Table shows the import coefficients adopted for use in the Study Group's runs of the input-output model.

Equations 70 to 78 are mainly definitional, but a remark is required on the assumed distribution among sectors of the import substitution activity which is built into equations 71 to 73. Tims distributed the import substitution activity in his equations between consumer goods manufacturing (35 percent) and intermediate goods manufacturing (65 percent) on the assumption that all the increase in pro-

TABLE 1-34
SECTORAL CAPITAL-OUTPUT RATIOS

Agriculture	3.5	Electric Power	8.7
Consumer Goods Manufacturing	1.8	Mining	5.0
Intermediate Goods Manufacturing	3.5	Construction	1.0
Capital Goods Manufacturing	2.3	Transport	5.0
Small Industry	1.4	Other Services	2.3

duction that could be expected from the investment goods industry by 1970 was already built into the model via the interindustry coefficients and the investment equations referred to above. With the longer time span covered by the West Pakistan analysis it seemed reasonable to allow for some import substitution in the form of increased production of investment goods, and so the equations given at the end of this section show the import substitution activity distributed between consumer goods manufacturing (25 percent), intermediate goods manufacturing (55 percent) and capital goods manufacturing (20 percent).

The final set of equations requiring elucidation is the group showing the relationship between investment in 1975 and the output of each sector in that year. Capital-output ratios were calculated specifically for the agricultural and electric power sectors, on the basis of the programs proposed in this report, while those for other sectors were taken from documents prepared by the Planning Commission and by the World Bank. Table 1-34 shows the incremental capital-output ratios estimated to be relevant for 1974/75. Lags of 1.5 years are built into all ratios, except that for the service sector, which is lagged half a year, following Tims (see "Growth Model for the Pakistan Economy"). In the equations, agriculture, transport and other services are treated separately, while the other sectors listed above are amalgamated; the average capital-output ratio for these sectors, with the ratio for each sector weighted by Perspective Plan targets for the output of each sector in 1975, is about 2:5. These ratios were in turn converted into the appropriate coefficients on the basis of the formulae given in Tims' report on his model.

The capital-output ratios given above are not surprising, except in the case of agriculture, for which the figure is much higher than suggested elsewhere for Pakistan. Tims used a capital-output ratio for this sector of 1:8. In another paper he estimates the unlagged capital-output ratio for West Pakistan agriculture during the Second Plan at 1:9 if no account is taken of investment during the Plan in the Indus Basin Works and 2:7 if those investments are included on the capital side. The capital-output ratios for agriculture were calculated by the Study Group without taking account of the Indus Basin Works. The main elements included by the Study Group on the capital side were: all private investment in irrigation and agriculture as projected in Volume Two of this Report, all proposed Plan allocations for public expenditures on irrigation and drainage works (including interest during construction), financial costs of the electricity distribution system required for connecting the public tubewells, all proposed public investment in surface water storage development (except for one-quarter of the costs of the basic reservoir structures at Tarbela, considered attributable to power, and, of course, all costs of power house and electrical and mechanical equipment for power generation) and, finally, most of the proposed public expenditures on agriculture other than the portion allocated for subsidies on fertilizer and insecticides. Using these items as

TABLE 1–35
EXPORTS TO EAST PAKISTAN BY SECTOR OF ORIGIN, 1960/61–1964/65
(Rs. million)

	1960/61	1961/62	1962/63	1963/64	1964/65
Agriculture	54	49	60	54	72
Consumer Goods Manufacturing	581	590	602	615	617
Intermediate Goods Manufacturing	129	164	123	123	108
Capital Goods Manufacturing	25	28	39	52	58
	789	831	824	844	855

the capital-base and assuming that agriculture would grow at 4.5 percent as projected in Volume Two of the Report, the Study Group found that the unlagged capital-output ratio for agriculture in West Pakistan would be about 2:7 during the Third Plan and 3:8 during the Fourth Plan; if the costs of Tarbela were totally excluded from the capital-base then the capital-output ratios would be about 2:3 over the Third Plan and 2:9 over the Fourth Plan. Thus the costs of the Tarbela dam make a significant difference to the capital-output ratio but even if they are left aside the capital-output ratio of agriculture in West Pakistan is high, as would

TABLE 1–36
PROJECTIONS OF NONAGRICULTURAL EXPORTS
(Rs. million, constant prices of 1962/63)

	Actual 1962/63	Estimated 1964/65		Projected 1974/75
Consumer Goods Manufacturing:	848	1,038	(8.2)	2,286
Exports Abroad	293	469	(13.0)	1,592
to East Pakistan	555	569	(2.0)	694
Intermediate Goods Manufacturing:	479	494	(9.0)	1,170
Exports Abroad	270	300	(12.0)	933
to East Pakistan	209	194	(2.0)	237
Investment Goods Manufacturing:	63	94	(20.0)	582
Exports Abroad	15	24	(20.0)	149
to East Pakistan	48	70	(20.0)	433
Transport and Communications:	152	173	(6.5)	325
Exports Abroad	56	64	(6.5)	120
to East Pakistan	96	109	(6.5)	205
All Other Services:	443	502	(6.5)	942
Exports Abroad	235	266	(6.5)	499
to East Pakistan	208	236	(6.5)	443
Total Nonagricultural Exports:	1,985	2,301	(8.7)	5,305
Abroad	869	1,123	(11.3)	3,293
to East Pakistan	1,116	1,178	(5.5)	2,012

TABLE 1-37
PROJECTIONS OF EXOGENOUS VARIABLES

	Value (Rs. million)			
	1962/63	1964/65	1974/75	Change (1964/65–1974/75)
Agricultural GPV	12,196	13,159	21,843	9,647
Gross Provincial Product Factor Cost (6%)	21,253	23,867	42,740	21,487
Savings (marginal rate of 23%)[a]	2,963	—	7,905	4,942

[a] Marginal savings rate of 23 percent of the increase in GPP at factor cost.

be expected in a situation where most agriculture is irrigated agriculture and where the price-structure appears to be still somewhat unfavorable to agriculture.

Exports, except for those of agricultural products, are exogenous to the model. The approach adopted in estimating the growth of exports was to follow closely Plan targets for foreign exports and to allow for continued trend ratio of growth in exports to East Pakistan. Exports in 1964/65 were estimated and the projected growth rates were applied for the 1964/65–1974/75 period. Table 1-35 shows recent growth in visible exports to East Pakistan by sector of origin, as estimated by the Study Group on the basis of Central Statistical Office data. Plan growth rates for foreign exports were estimated on the basis of the Third Plan document and other Planning Commission papers made available to the Study Group. Table 1-36 shows the base-year export figures from the input-output table, the estimated exports in 1964/65 and the projected growth in exports to 1974/75. Figures in parentheses between the last two columns show the implicit average annual growth rates. This set of export projections was used for all runs of the projection model.

Of the three remaining exogenous variables, GPP, Savings and GVP of Agriculture, the first two were varied in different runs of the model while the last was always kept constant. The growth rate assumed for agriculture was 5.2 percent per annum in terms of GPV, corresponding to about 4.5 percent per annum in terms of Gross Value Added by agriculture; these growth rates are those projected in Volume Two of the Report on the basis of a detailed examination of prospective yield growth and increase in cropped acreage. Various growth rates for GPP and various marginal savings rates were used. All figures were calculated in 1962/63 prices and the assumed growth rates were applied to estimated historical figures for 1964/65. Table 1-37 gives some illustrative examples.

APPENDIX TABLE 1-1
INPUT-OUTPUT PROJECTION MODEL OF WEST PAKISTAN
(base-year: 1962/63; projected year: 1974/75)

Inputs into Agriculture

(1) $x_{11} = .0623\ X_1$
(2) $x_{21} = .0013\ X_1$
(3) $x_{31} = .1403\ X_1$
(4) $x_{41} = .0034\ X_1$
(5) $x_{61} = .0323\ X_1$
(6) $x_{71} = .1705\ X_1$

Inputs into Consumer Goods Manufacturing

(7) $x_{12} - .3000\,X_2 = 0$
(8) $x_{22} - .0383\,X_2 = 0$
(9) $x_{32} - .1000\,X_2 = 0$
(10) $x_{42} - .0097\,X_2 = 0$
(11) $x_{62} - .0226\,X_2 = 0$
(12) $x_{72} - .1402\,X_2 = 0$

Inputs into Intermediate Goods Production

(13) $x_{13} - .1929\,X_3 = 0$
(14) $x_{23} - .0050\,X_3 = 0$
(15) $x_{33} - .1569\,X_3 = 0$
(16) $x_{43} - .0070\,X_3 = 0$
(17) $x_{63} - .0519\,X_3 = 0$
(18) $x_{73} - .1226\,X_3 = 0$

Inputs into Investment Goods Industries

(19) $x_{14} - .1700\,X_4 = 0$
(20) $x_{24} - .0400\,X_4 = 0$
(21) $x_{34} - .0501\,X_4 = 0$
(22) $x_{44} - .0266\,X_4 = 0$
(23) $x_{64} - .0347\,X_4 = 0$
(24) $x_{74} - .0677\,X_4 = 0$

Inputs into Construction

(25) $x_{15} - .0197\,X_5 = 0$
(26) $x_{25} - .1133\,X_5 = 0$
(27) $x_{35} - .1795\,X_5 = 0$
(28) $x_{45} - .0452\,X_5 = 0$
(29) $x_{65} - .1314\,X_5 = 0$
(30) $x_{75} - .0140\,X_5 = 0$

Inputs into Transport and Communications

(31) $x_{26} - .0170\,X_6 = 0$
(32) $x_{36} - .0637\,X_6 = 0$
(33) $x_{46} - .1216\,X_6 = 0$
(34) $x_{66} - .0321\,X_6 = 0$
(35) $x_{76} - .0334\,X_6 = 0$

Inputs into All Other Services

(36) $x_{27} - .0190\,X_7 = 0$
(37) $x_{57} - .0122\,X_7 = 0$
(38) $x_{67} - .0217\,X_7 = 0$
(39) $x_{77} - .0010\,X_7 = 0$

Consumption Expenditures

(40) $c_1 - .2355\,C = 0$
(41) $c_2 - .4566\,C = 0$
(42) $c_3 - .0103\,C = 0$
(43) $c_4 - .0230\,C = 0$
(44) $c_5 - .0091\,C = 0$
(45) $c_6 - .0420\,C = 0$
(46) $c_7 - .1365\,C = 0$

Investment by Sector of Origin

(47) $i_4 - .0800\,i'_1 - .2200\,i'_{2-5} - .4000\,i'_6 = 0$
(48) $i_5 - .7800\,i'_1 - .2700\,i'_{2-5} - .3800\,i'_6 - 1.000\,i_7 = 0$
(49) $i_6 - .0100\,i'_1 - .0500\,i'_{2-5} - .0200\,i'_6 = 0$
(50) $i_7 - .0150\,i'_1 - .0800\,i'_{2-5} - .0400\,i'_6 = 0$

Indirect Taxes Net of Subsidies

(51) $t_1 = .0389\, X_1$

(52) $t_2 - .0594\, X_2 = 0$

(53) $t_3 - .0808\, X_3 = 0$

(54) $t_4 - .0779\, X_4 = 0$

(55) $t_5 - .0320\, X_5 = 0$

(56) $t_6 - .0329\, X_6 = 0$

(57) $t_7 - .0010\, X_7 = 0$

(58) $t_c - .0098\, C = 0$

(59) $t_i - .0250\, i'_1 - .0800\, i'_{2-5} - .0400\, i'_6 = 0$

(60) $t_e - .0171e_1 \div .0171ES = .0171e_2 + .0171e_3 + .0171e_4 + .0171e_6 + .0171e_7$

Imports of Goods and Services

(61) $m_1 = .0125\, X_1$

(62) $m_2 - .1207\, X_2 = 0$

(63) $m_3 - .0756\, X_3 = 0$

(64) $m_4 - .2300\, X_4 = 0$

(65) $m_5 - .1407\, X_5 = 0$

(66) $m_6 - .1114\, X_6 = 0$

(67) $m_7 - .0082\, X_7 = 0$

(68) $m_c - .0772\, C = 0$

(69) $m_i - .0900\, i'_1 - .3000\, i'_{2-5} - .1200\, i'_6 = 0$

Definitions of Sectoral Production

(70) $x_{11} + x_{12} + x_{13} + x_{14} + x_{15} + c_1 + e_1 = X_1$

(71) $X_2 - x_{21} - x_{22} - x_{23} - x_{24} - x_{25} - x_{26} - x_{27} - c_2 - .2500\, E_s = e_2$

(72) $X_3 - x_{31} - x_{32} - x_{33} - x_{34} - x_{35} - x_{36} - c_3 - .5500\, E_s = e_3$

(73) $X_4 - x_{41} - x_{42} - x_{43} - x_{44} - x_{45} - x_{46} - c_4 - i_4 - .2000\, E_s = e_4$

(74) $X_5 - x_{57} - c_5 - i_5 = 0$

(75) $X_6 - x_{61} - x_{62} - x_{63} - x_{64} - x_{65} - x_{66} - x_{67} - c_6 - i_6 = e_6$

(76) $X_7 - x_{71} - x_{72} - x_{73} - x_{74} - x_{75} - x_{76} - x_{77} - c_7 - i_7 = e_7$

Definition of GNP

(77)
$$
\begin{aligned}
& X_2 - x_{12} - x_{22} - x_{32} - x_{42} - x_{62} - x_{72} - m_2 - t_2 \\
& \qquad - x_{11} - x_{21} - x_{31} - x_{41} - x_{61} - x_{71} - m_1 - t_1 \\
& + X_3 - x_{13} - x_{23} - x_{33} - x_{43} - x_{63} - x_{73} - m_3 - t_3 \\
& + X_4 - x_{14} - x_{24} - x_{34} - x_{44} - x_{64} - x_{74} - m_4 - t_4 \\
& + X_5 - x_{15} - x_{25} - x_{35} - x_{45} - x_{65} - x_{75} - m_5 - t_5 \\
& + X_6 - x_{26} - x_{36} - x_{46} - x_{66} - x_{76} - m_6 - t_6 \\
& + X_7 - x_{27} - x_{57} - x_{67} - x_{77} - m_7 - t_7 = Y - X_1
\end{aligned}
$$

Savings

(78)
$$
\begin{aligned}
& i'_1 + i'_{2-5} + i'_6 + i'_7 + e_1 + t_e + E_s \\
& \qquad - m_1 - m_2 - m_3 - m_4 - m_5 - m_6 - m_7 - m_c - m_i \\
& \qquad = S - e_2 - e_3 - e_4 - e_6 - e_7
\end{aligned}
$$

Investment-Output Relations

(79)
$$
\begin{aligned}
& i'_1 + .1883x_{11} + .1883x_{21} + .1883x_{31} + .1883x_{41} \\
& \qquad + .1883x_{61} + .1883x_{71} + .1883m_1 + .1883t_1 = .1883X_1
\end{aligned}
$$

(80)
$$
\begin{aligned}
& i'_{2-5} - .2899X_2 + .2899x_{12} + .2899x_{22} + .2899x_{32} + .2899x_{42} \\
& \qquad + .2899x_{62} + .2899x_{72} + .2899m_2 + .2899t_2 - .2899X_3 \\
& \qquad + .2899x_{13} + .2899x_{23} + .2899x_{33} + .2899x_{43} + .2899x_{63} \\
& \qquad + .2899x_{73} + .2899m_3 + .2899t_3 - .2899X_4 + .2899x_{14} \\
& \qquad + .2899x_{24} + .2899x_{34} + .2899x_{44} + .2899x_{64} + .2899x_{74} \\
& \qquad + .2899m_4 + .2899t_4 - .2899X_5 + .2899x_{15} + .2899x_{25} \\
& \qquad + .2899x_{35} + .2899x_{45} + .2899x_{65} + .2899x_{75} + .2899m_5 \\
& \qquad + .2899t_5 - .0407E_s = 0
\end{aligned}
$$

(81)
$$
\begin{aligned}
& i'_6 - .3633X_6 + .3633x_{26} + .3633x_{36} + .3633x_{46} \\
& \qquad + .3633x_{66} + .3633x_{76} + .3633m_6 + .3633t_6 = 0
\end{aligned}
$$

(82)
$$
\begin{aligned}
& i'_7 - .1519X_7 + .1519x_{27} + .1519x_{57} + .1519x_{67} \\
& \qquad + .1519x_{77} + .1519m_7 + .1519t_7 = 0
\end{aligned}
$$

(83) $M - m_1 - m_2 - m_3 - m_4 - m_5 - m_6 - m_7 - m_c - m_i = 0$

(84) $E - e_1 - t_e - E_s = e_2 + e_3 + e_4 + e_6 + e_7$

Population Projection

The irrigation consultant and the power consultant used different forecasts of the future population of West Pakistan in arriving at their recommendations. Both started from a base-year population of 51.2 million in 1965, but the power consultant projected a linear annual increase of population at 2.8 percent per annum, whereas the irrigation consultant used a number of different growth patterns. These rates are summarized in Table A1-1. Although the totals for 1985 are quite comparable, the differences among the consultants in their projections of the distribution of the population between urban and rural areas and between the different areas of the country are substantial.

TABLE A1-1
ANNUAL AVERAGE POPULATION GROWTH RATES USED BY IRRIGATION CONSULTANT
(percent)

	1965–70	1970–75	1975–80	1980–85	Implied 1985 Population	1985–2000
					(million)	
IACA Low	2.4	2.75	2.5	2.4	84	2.0
IACA High	2.4	2.75	3.1	3.0	89	2.75
Plancom High	2.4	2.75	2.75	2.75	88	2.4
Power	2.8	2.8	2.8	2.8	88	—

Other projections of the population of West Pakistan have been made, notably by the Pakistan Planning Commission and by the U.S. Bureau of the Census.[1] The third row in the Table A1-1 apparently represents one of the Planning Commission's several projections. It is a growth pattern based on the assumption that the family planning program will not have a visible effect on the overall population growth rate before 1985. It does imply, of course, that family planning will have a sufficiently large effect on the birthrate for declines here to offset the effect of public health measures in reducing the deathrate. Since this growth pattern was formulated, doubts have grown as to whether the current population growth rate assumed (2.4 percent) is correct. PGE (Population Growth Estimation) studies have suggested that the current growth rate may be as high as 3.0 (birthrate of approximately 50/1000 and deathrate of 20/1000). The U.S. Census Bureau study uses a projection model and forms different sets of assumptions as to future trends in fertility and mortality rates. The study concludes that the 1985 population of West Pakistan might be, at lowest, 88.7 million. If fertility does not decline or if fertility decline is largely offset by further mortality decline then 1985 population would be substantially higher, quite possibly over 100 million.

[1] James W. Brackett and Donald J. Akers, "Projections of the Population of Pakistan, by Age and Sex: 1965–1986," U.S. Dept. of Commerce, June 1965.

The U.S. Census Bureau study may be unduly pessimistic, because it is based on the early PGE results which are still not fully confirmed and because it makes the rather artificial assumption that the family planning program will cease to expand after the initial target date of 1972, by which time one quarter of the women of childbearing age are expected to be using some contraceptive technique. On the one hand this target is probably considered too optimistic for 1972, but on the other hand the program could, with an adequate effort, expand rapidly between now and 1972 and continue to expand thereafter.

The population projection attached is based on the 1961 census adjusted for an estimated 7 percent undercounting. It is based on the assumption that the current rate of population growth is about 2.6 percent and that the family planning program, while it gets the high priority which it deserves, will not be sufficient to have a noticeable effect on the overall population growth rate until 1980. The growth rate assumed for the period 1980–85 is 2.7 percent, as the effects of population control measures begin to outweigh a continuing decline in the mortality rate.

The regional distribution of the population is estimated on the basis of trend rates of growth and the likelihood that the Sind will gradually get an increasing share of the total population. Relatively substantial industrial growth is likely in

TABLE A1-2
PROJECTION OF POPULATION DISTRIBUTION[a]
(millions)

	1964	1965	1970	1975	1980	1985
North						
Urban[b]	5.65	5.95	7.70	10.0	12.9	16.7
Rural	32.92	33.55	36.90	40.8	45.7	50.0
Total	38.57	39.50	44.6	50.8	58.6	66.7
Upper Sind						
Urban	0.39	0.41	0.5	0.7	0.9	1.2
Rural	3.25	3.34	3.7	4.1	4.8	5.1
Total	3.64	3.75	4.2	4.8	5.7	6.3
Lower Sind						
Urban	0.76	0.80	1.1	1.4	1.9	2.5
Rural	3.00	3.06	3.4	3.8	4.2	4.6
Total	3.76	3.86	4.5	5.2	6.1	7.1
Baluchistan						
Urban	0.12	0.12	0.15	0.2	0.2	0.3
Rural	1.39	1.42	1.65	2.0	2.3	2.4
Total	1.51	1.54	1.8	2.2	2.5	2.7
Karachi						
Urban	2.42	2.55	3.2	4.0	5.1	6.2
Total	49.90	51.20	58.3	67.0	78.0	89.0
Total Urban	9.34	9.83	12.65	16.3	21.0	26.9
Total Rural	40.56	41.37	45.65	50.7	57.0	62.1
Rural (Census)[c]		38.00	41.0	44.0	47.0	50.5

[a] As of January 1st of each year.

[b] "Urban" is defined for the purposes of this table as including all cities with populations in excess of 25,000. Allowance is made in the urban growth rates for the accession of new cities into the "above 25,000" category as a result of crossing this threshold level. Therefore, the 1985 figures purport to indicate the total population in each region which will then be living in cities of over 25,000 population size.

[c] For purposes of comparison "rural" population is here defined as in the 1961 Census—i.e., excluding all settlements with a population exceeding 5,000 as well as other places which the Provincial Director of the Census determined to have "pronounced urban characteristics" such as "common utilities, roads, sanitation, schools and specially nonagricultural occupation of the people."

the Sind (especially in Lower Sind) as development begins to spread out from Karachi; and there are a number of areas newly irrigated by Gudu and Ghulam Mohammed Barrages which have yet to be fully settled. Urban population (here defined as the population living in cities over 25,000) is projected to grow at slightly more than 5 percent over the 20-year period.[1] The growth rate of Karachi is assumed to slacken somewhat, in line with past trends, to about 4.5 percent per annum, while the growth of urban population in the Sind will remain above the national average for the perspective plan period.

[1] This is supposed to be in line with the Planning Commission projections. These include a growth rate of the total urban population of about 5.3 percent, but are based on the census definition of "urban" which is much broader than the definition used here. Between 1951 and 1961 urban population on the census definition appears to have grown more rapidly (average annual rate of about 5.6 percent) than urban population defined as those living in cities which by 1961 were larger than 25,000 (average annual rate of about 5.4 percent). Therefore we use an urban population growth rate somewhat below the Planning Commission's.

Foreign Exchange Rationing and the Scarcity Value of Foreign Exchange

Pakistan's development efforts have been severely hampered in recent years by an acute shortage of foreign exchange. Numerous policy measures have been taken to try to minimize the constraint. The result has been the creation of what is in effect a multiple exchange rate system, in which different classes of imports and exports are subject to different exchange rates and to a variety of more direct controls and incentives. This complex system is continually adjusted in the light of current import needs and current availability of foreign exchange.

One important step in the creation of this multiple exchange rate system was the establishment in 1959 of the Export Bonus Voucher Scheme which now covers about 50 percent of Pakistan's exports. Under this scheme the effective exchange rate for an exporter depends upon the bonus rate to which he is entitled (20 percent of the f.o.b. value of his exports if he is exporting cotton manufactures, milled rice or sugar, and 30 percent if he is exporting other manufactured goods or selling goods for use in the Indus Basin Project) and on the premium at which the vouchers can currently be sold. The premium has averaged about 50 percent. Thus, there are basically three rates at which exporters can convert their foreign exchange earnings, depending on the commodity they export—the official rate of Rs. 4.76 to the U.S. dollar, and, under the Export Bonus Voucher Scheme, rates of Rs. 6.20 and Rs. 6.90 to the dollar. Inward remittances by Pakistanis living abroad also carry a 30 percent voucher or a rate of about Rs. 6.90 to the dollar.

For imports there are basically two exchange rates—the official Rs. 4.76 to the dollar covering 80-90 percent of imports and the rate of about Rs. 12.00 to the dollar, which results from the Bonus Voucher Scheme,[1] for the remainder. The level of imports is controlled by tariffs, fiscal and monetary policy and, above all, by licensing policy. Foreign exchange purchased from the State Bank on the basis of Bonus Vouchers is available for the import of certain specified commodities. Most imports are obtained under specific licenses or under the "Free List," originally introduced in 1964, withdrawn in 1965 but reinstated in 1966 although with restrictive characteristics. When the "Free List" was introduced tariffs were raised on many of the items covered by the list. Nevertheless, the licensing system itself remains the main instrument of rationing. Responsibility for deciding which goods will be covered by different types of licenses and, in the case of industrial imports, the proportion of the import requirements of each industry which will be covered by different types of licenses rests with the Government. A high level Foreign Exchange Committee prepares an annual Foreign Exchange Budget which sets

[1] Importers using Bonus Vouchers must first buy the voucher which averages about Rs. 150. This entitles them to purchase Rs. 100 of foreign exchange at the official exchange rate.

aside a portion of the foreign exchange expected to be available from exports, transfers and aid-receipts to cover imports under the Export Bonus Voucher Scheme; it allocates another portion to the public sector and distributes it among the various ministries and semi-public corporations (with specification as to how much may be spent on development imports and how much on nondevelopment imports) and then leaves the remainder (usually about two-thirds) to the private sector. The Chief Controller of Imports and Exports, the chief licensing authority in the country, then has the responsibility of allocating licenses among private sector importers on the basis of stated needs, market reports indicating price trends of imported commodities and officially set priorities as to what the market should need in order to bring about an optimum allocation of resources.

The stringent measures which have had to be taken to control the use of foreign exchange indicate that it has a scarcity value substantially above the current official exchange rate. Recognizing this, the Third Plan states: "The scarcity price of foreign exchange should be appropriately reflected to the economy so that there is an incentive to use less foreign exchange and more domestic resources. This will call for a revision in the present tariff policy, reexamination of the current interest rate structure and use of shadow prices for the appraisal of at least the major projects in the Third Plan."

Shadow prices are attributed to specific factors for planning purposes in cases where actual prices fail to indicate the real scarcity of the factors in question. These shadow prices should represent the marginal value productivity of each factor after all alternative uses for the factor have been taken into account. As such, they should be the outcome of an optimizing planning model and, especially for the purposes of long-term planning, they should be in the form of a time series, indicating the anticipated changing degree of scarcity of the factor in question over the years. While the Pakistan Planning Commission is working towards such economic models, no results were available regarding shadow prices when this report was being prepared. Nevertheless, it is possible to generate some conception of the real scarcity value of foreign exchange in Pakistan on the basis of study of the current situation.

Several efforts have been made to identify the present scarcity value of foreign exchange in West Pakistan on the assumption that little further could be done at the present stage to boost overall export earnings—or, in other words, that foreign demand for Pakistan's exports is too price-inelastic for foreign exchange earnings to be significantly increased by any further manipulation of the effective exchange rates received by exporters. This assumption may be reasonable at the present stage, though it could become less so; even with an important item like cotton, Pakistan is still such a relatively small factor in total world supply that demand is probably price-elastic and the possibility of expanding exports by cutting prices will probably increase as Pakistan's exports become more diversified and include more manufactured goods. However, the present study of the current situation has not been sufficiently comprehensive to determine whether foreign exchange earnings, as well as foreign capital inflow, could be greatly increased by changes in exchange rate policy, fiscal policy, monetary policy or licensing policy. For the purposes of analysis, however, we assume a perspective very similar to that of the Foreign Exchange Committee which has responsibility for deciding how anticipated supplies of foreign exchange can best be divided among the various sectors of the economy.

The end result of the process of import budgeting described above is a particular allocation of imports among different sectors and a complementary pattern of domestic prices for imported goods. Some of the goods, for instance most of those going to the government, do not enter into the market again, while others, such as those imported by manufacturers for their own use, enter only indirectly as components of finished products. However, a relatively large proportion of total imports enters into commercial channels for resale in unchanged form. The Pakistan Institute of Development Economics selected a sample of imported goods representative of the different economic categories of imports (consumer goods, intermediate goods and capital goods) and, within these, of the proportion imported under different types of licenses. They then gathered domestic market prices for the representative goods in Karachi in June-August 1964 and in December 1964-January 1965. Pal has presented the results of these surveys[1] and compared the domestic market prices for the commodities with their c-and-f prices. A part of the difference between the two prices is attributed to the tariff and part to the sales tax, but Pal finds that a relatively large proportion of the final domestic price, an average of about 60 percent of landed cost (where landed cost includes c-and-f price, tariff and sales tax) constitutes an importer's mark-up. Attributing imports a "normal" level of mark-up of about 12 percent to cover costs and "normal" profit, Pal concludes that the scarcity premium on foreign exchange in West Pakistan in mid-1964 was about 50 percent. In a subsequent article, based on market prices gathered in a later period when the "Free List" had been extended and the prices of some imported goods had consequently fallen slightly, he made an allowance—necessarily arbitrary—of 33 percent for the fall in mark-ups that might result if all private imports were sold on the open market in Pakistan and thus concluded that the scarcity value, on these assumptions, was about 30 percent.

These results are primarily of interest for the extremely high level of importer's mark-up which they indicate to exist in Pakistan at present. This high mark-up (somewhat higher in West Pakistan than in East Pakistan) results from the combination of relatively strong demand for imported goods in West Pakistan and the severe rationing of foreign exchange which is enforced by the licensing system. Pal demonstrates that a mere addition of competing merchants into West Pakistan's import trade, without expansion of the foreign exchange available for imports, would not be likely to cause significant reductions in the domestic prices of most imported goods. However, there is a possibility of diverting a larger proportion of high mark-ups which result from domestic supply and demand patterns to the government or to the export sector by additional taxes or by extension of schemes such as the Bonus Voucher.

Pal's results are of course inevitably based on a relatively narrow sample of the total import trade—certain individual commodities, which are assumed to be representative for whole categories of imports, in the Karachi market. They do not cover direct imports by industrialists under license, but the evidence is that industrialists who have licenses receive, as part of their profit on final sales, much the same profit on the import component as importers receive directly on resale of similar goods imported by them. In regard to government imports there is

[1] Mati Lai Pal, "The Determinants of the Domestic Prices of Imports," Pakistan Development Review, Winter 1964 and "Domestic Prices of Imports in Pakistan: Extension of Empirical Findings," Pakistan Development Review, Winter 1965.

probably no such mark-up. The simple assumption has to be made, as pointed out above, that the Foreign Exchange Committee allocates resources in such a way that the marginal value product of foreign exchange is approximately equalized among the different sectors of the economy.

In order to derive an indicator of the current scarcity value of foreign exchange appropriate for use in the Indus Study we have made use of the price data presented by Pal but we have adopted definitions slightly different from his. As pointed out, tariffs are an important part of the overall rationing system and they have been used to an increasing extent as the licensing system has been liberalized. 'Economic' (as opposed to financial) prices used in the Indus Study for all economic comparisons are all cited exclusive of indirect taxes. The scarcity premium applied to the foreign exchange components of these prices should therefore include an allowance for tariffs. Another divergence in our calculations from those of Pal is that we make a somewhat larger allowance for importer's normal mark-up—20 percent of landed cost in place of Pal's 12 percent—in order to ensure avoidance of any exaggeration of the scarcity premium on this score.

The real scarcity value of foreign exchange, as defined for our purposes, was thus derived by estimating a domestic wholesale price for imported goods, net of a 20 percent mark-up on landed costs to cover distribution, and setting that over the estimated c-and-f price for the goods. A so-called "effective price to wholesaler" for each of the goods for which Pal provides data was first computed, adding tariff, sales tax, Bonus Voucher (where appropriate), and importer's mark-up to the c-and-f price, subtracting 20 percent of landed cost for importer's normal mark-up and expressing the final result as an index of the c-and-f price of the goods. The goods had been selected by Pal to be reasonably representative of different groups of imports as defined by the PSITC four-digit code. The "effective prices to wholesaler" were therefore weighted by 1964/65 imports into West Pakistan in the relevant four-digit category and the results were summed in the groups indicated in the following table. The implicit exchange rate for each group of commodities is then defined as an index of the official rate of Rs. 4.76 to the dollar by dividing imports in the group, valued at the "effective prices to wholesaler" by the same imports valued at Rs. 4.76 to the dollar. The "effective price to wholesaler" of each group of commodities may be defined as

$$\sum_{i=1}^{n} M_i \quad [0.8\,(1 + t_i + s_i + B) + K_i]$$

Where M_i = c-and-f value of an import category in 1964/65

t_i = tariff rate on the representative commodity, expressed as a percentage of its c-and-f value

s_i = sales tax on the representative commodity, expressed as a percentage of its c-and-f value

B = Bonus Voucher, always taken as 150 percent of the c-and-f value of imports of a commodity, for which it was relevant

K_i = importer's mark-up on the representative commodity, expressed as a percentage of its c-and-f value.

Column (1) in the following table gives the value of n for each of the groups. Column (4) lists the implicit exchange rates, defined as:

$$\frac{\sum_{i=1}^{n} M_i \quad [0.8\ (1 + t_i + s_i + B) + K_i]}{\sum_{i=1}^{n} M_i}$$

The results shown in the last column of the table indicate the wide spread of effective exchange rates under which different commodities are imported. Consumer goods enter at a rather uniformly high implicit exchange rate, but raw materials and capital goods are subject to very different effective rates, depending on whether they happen to be on the "Free List" or on license. Capital and intermediate goods on the "Free List" enter at about 150 percent of the official exchange rate. The implicit exchange rate figure which is derived from adding together all

TABLE A2-1
EFFECTIVE EXCHANGE RATE FOR WEST PAKISTAN'S IMPORTS, 1964/65

	(1) No. of Commodities	(2) cif Value of Imports (Rs. mill.)	(3) Effective Price to Wholesaler (Rs. mill.)	(4) Implicit Exchange Rate (multiple of Rs. 4.76)
Consumer Goods				
Licensed Items	21	154.9	452.4	2.92
Bonus Items	13	96.8	279.8	2.89
Free List Items	2	13.9	16.7	1.20
Total		265.6	748.9	
Total Consumer Good Imports		[384.0]		
Raw Materials				
Licensed Items (for consumer goods)	15	242.4	479.9	1.98
Free List Items (for consumer goods)	8	70.0	95.9	1.37
Subtotal		312.4	575.8	1.84
Licensed Items (for capital goods)	8	22.5	42.8	1.90
Free List Item	14	85.9	115.9	1.35
Subtotal		108.4	157.7	1.46
Total		420.8	734.5	1.75
Total Intermediate Good Imports		[2,296.0]		
Capital Goods				
Licensed Items	10	163.5	333.5	2.04
Free List Items	17	240.0	348.0	1.45
		403.5	681.5	1.69
Total Capital Good Imports		[1,020.0]		
All Goods		1,089.9	2,164.9	2.00
Grand Total All Merchandise Imports		[3,700.0]		

groups for which data are available is 200 percent of the official rate. However, the figures[1] on total imports in 1964/65 within each of the broader categories (consumer goods, intermediate goods and capital goods) indicate that the commodities for which data are available may give a biased result. If the implicit exchange rate derived for each group is weighted by the total cif values of imports in each group, then the overall implicit rate of exchange appears to be 185 percent of the current official rate. This should be regarded as a minimum because the computations have been based on very conservative assumptions. For instance we have used a high "normal" mark-up allowance for all categories of trade, although it should likely be lower for raw material and capital goods imports. Also the figures we have used may well contain too high a proportion of trade on goods on the "Free List," on which tariffs and mark-ups tend to be low, relative to the amounts of trade under license or under bonus.

Another way of approaching this analysis would be to consider the proportions of total imports which entered under the different import procedures. It has been estimated that, before the temporary adjustments to the import system in Autumn 1965, the distribution of private imports was 40 percent on Free List, 20 percent on Bonus Voucher, and 40 percent on direct licenses. This also appears to be approximately the pattern which was restored in 1966. Aggregating the rates for each of these categories in the attached table and weighting the results with these proportions would yield an average effective import price of about 1.9-2.0 times the existing official exchange rate.

The conclusion to be drawn from these calculations is that to consider recommendations for a development program without taking account of something close to a 100 percent premium on the current foreign exchange rate would be to run a severe risk of misallocating resources.

[1] Shown in parentheses beneath the relevant categories in Table A2-1.

SUPPLEMENTAL PAPER II

The Load Forecast and the Economic Framework

THE ROLE OF THE LOAD FORECAST

Establishing a reasonable projection of future demand for the stream of goods that will be produced as a result of investment of capital in a project is always an important part of project evaluation. There are a number of reasons why it is particularly important in the electric power sector. First, power projects tend to have exceptionally long lead times; Tarbela, which is expected to take about eight years to build, is somewhat unusual but even gas turbines require two-three years' lead time when the delays involved in securing clearance at different levels of government and obtaining external financing are taken into account as well as the time required for design, bidding, letting contracts, land acquisition, construction, final testing, etc. In the power sector, there is little possibility of responding quickly to a favorable market situation, indicated by shortages and rising prices, with a quick switch of resources or construction of a small plant, as there is in many other sectors of the economy. Second, mistakes in forecasting power loads—and international experience shows that they are all too frequent—tend to be expensive. Partly this is related to the first point; generation and distribution of power to consumers require heavy capital investments which take a relatively long time to execute. Investments in power facilities represent a sizable part of a country's total investment. In West Pakistan, for instance, power supplies were short throughout the Second Plan period and a serious power crisis developed soon after completion of the Plan period; nevertheless the public share alone of total investment in power facilities was 15 percent of public investment and 6 percent of total investment in the Province during the Plan period. Over-investment in power can thus mean a waste of capital of significant proportions. But the losses that result from under-investment equally tend to be large. Because power is consumed in relatively small quantities by very large numbers of consumers the effects of power shortages tend to be widely felt. Once equipment driven by electric power has been installed, there is generally little possibility of substituting electricity with some other source of energy. Moreover, the brunt of any power shortage has generally to be borne by those using power for production purposes in agriculture or industry rather than by domestic or commercial consumers—partly because the industrial and agricultural loads tend to occur in larger blocks which can be more easily controlled, partly because of the technical, social and political difficulties of shedding urban residential and commercial loads. Power shortages therefore tend to have serious effects on the output of other productive sectors of the economy and to cause hesitation on the part of potential investors, thus curtailing economic growth.

From the economic point of view, the evaluation and justification of power projects are rather hard to handle. Electric power is neither clearly substitutable nor, despite what was said in the previous paragraph, clearly indispensable. Before consumers have committed themselves to equipment driven by electricity they may face a choice between such equipment and alternatives driven by other forms of energy. But the extent of choice varies widely in different fields of consumption; machinery powered by natural gas is a reasonable alternative in some fields in West Pakistan such as domestic heating and air-conditioning and kiln firing, but in many other fields, such as lighting and much technical production equipment, adequate substitutes do not exist. For this reason, because of the prior commitment to equipment using only one type of energy that is generally unavoidable, and because of the great economies of scale involved in production of electric power, electricity does not sell in a free market which sets a price for it in competition with other forms of energy. It is rather sold at administered prices which give little indication of what people would be prepared to pay for it. Hence the benefits of an electric power project cannot reasonably be evaluated in the way that the benefits of many capital investments can be computed, by projecting a stream of output, multiplying the physical outputs by projected prices and subtracting current costs for labor, materials, etc. But because electric power is not clearly indispensable any more than it is substitutable, the other widely-used technique of projecting benefits—estimating values for output at one remove from the market—is also not relevant. The value of irrigation water, for instance, can often be reasonably projected by attributing to it the entire difference between the market value of the agricultural production which it makes possible and the market value of other inputs—fertilizer, seed, etc.—used in the production process. Publicly generated electric energy is not as clearly indispensable as irrigation water, nor is it nearly such an important input in most production processes as irrigation water is in agriculture.

Since these customary means of benefit evaluation are inappropriate to power projects resort has been had in this Report to a technique which is often used in the utility field and which puts the physical load forecast in a place of tremendous importance. The power load is projected and those power projects are selected which meet the load at least cost. The "net benefits" of a power project are defined as the difference between the cost of meeting the load with the project in question and the cost of meeting it with the "cheapest alternative" project. The calculations are almost entirely internal to the power sector once the load forecast has been made. Everything depends on the load forecast—it bears a dual responsibility, serving for both the physical demand projection and the price projection that can be made for most commodities. If the load forecast is too high relative to growth of demand then the net benefits of a project will appear too high and, in addition, unduly large amounts of money will be devoted to the power sector; large projects may be undertaken before they are warranted. If it is too low, on the other hand, then serious disruption may result in the rest of the economy and economic growth may be curtailed, as it has been by the recent shortage of power in West Pakistan.

Thus the load forecast is the crucial link between the power sector and the rest of the economy and between planning for each. One of the main tasks of this report was to reassess the benefits of the Tarbela Project. Another important task was to identify the other generating and transmission investments that should be made over the Perspective Plan period and particularly over the next decade or so, given the fact that Tarbela Dam would be completed by about 1975. Justification of Tarbela and selection of an appropriate mix of supporting projects depend intimately on the load forecast, and it was important therefore to see that the load forecast used was consistent with the other plans and proposals coming out of the Indus Special Study. There were other reasons too why the relationship between the load forecast and general economic growth projections for West Pakistan was considered important. In the first place, there is wide agreement that, because of the crucial nature of the load forecast in planning the internal development of the power sector and in deciding appropriate patterns for allocation of government investment funds among sectors, load forecasting in West Pakistan needs to be much more closely linked with economic planning than it is at present. In the second place, one of the purposes of the Indus Special Study was to make a contribution to the serious effort at long-term planning that is underway in Pakistan by going into depth in the agriculture and power sectors and trying to assess the attainability of targets and to identify the specific bottlenecks that might arise, the resources that would be needed for meeting projected demands, etc. To be useful for this purpose, the load forecast needed to be cast in a framework compatible with planning categories used in the general planning effort.

The Time Span of the Load Forecast

Load forecasts covering various numbers of years are useful for various different purposes, but the time span of the load forecast required for the studies incorporated in this report was set mainly by the long time required to build and then to absorb fully the power from Tarbela. Rather specific short term (2-3 year) load forecasts are needed in the operation of a power system for formulating maintenance programs, building up fuel stocks at thermal stations and planning seasonal power exchanges. For purposes of planning additions to generation and transmission capacity a longer term forecast is needed. Insofar as two to four years generally elapse between a definite decision to add thermal capacity and completion of installation, a five-year load forecast may be adequate to ensure the sheer availability of capacity to meet loads. But to enable a correct decision to be taken as to the type and size of generator required and to ensure its most economic integration into the system a longer load forecast—for about a 10-year period—is the minimum required. When a substantial hydro development is envisaged these arguments are reinforced and an even longer perspective is required to decide how the plant compares with other potential projects, when it should be installed and how it will affect the intermediate development of the system. Both Mangla and Tarbela, for instance, have minimum capabilities at full development comparable with the present peak on the Northern Grid of about 500 mw. Critical questions are when the units should be installed at each plant, whether and when thermal capability will be required to firm them up, and what amount of energy will be available from them for long-distance transmission to areas outside the Northern

Grid. To handle these questions a 20-year period was adopted for the load forecast. Because views about the answers to these questions affect matters requiring early decision, such as dam design, transmission line investment and the intermediate installation of thermal capacity, so too a 20-year load forecast has considerable relevance for the present. The fact that long-distance transmission of power is an important subject in West Pakistan, requiring some early decisions about large investments in high-tension lines, means also that reasonable estimates are needed of the future regional distribution of power loads in different parts of the Province.

WAPDA Load Forecasting

One way of making a long-term load forecast for West Pakistan would be to use the short-range forecasts prepared by WAPDA in recent years and then to extrapolate them in one way or another. The first comprehensive survey of the power market in West Pakistan, outside of Karachi, was carried out by Harza Engineering Company under the auspices of WAPDA in 1961/62. The survey, results of which were published in a report entitled Power Market Survey and Forecast of System Loads (June, 1963), attempted to give a comprehensive coverage of existing loads (whether on WAPDA, other utilities or supplied by self-generation), potential loads (i.e., including loads in existence but not yet electrified) and actual prospective WAPDA loads over a five-year period. Loads were built up item by item to give a comprehensive picture for each of the 11 Civil Divisions outside Karachi and they were then reassembled on a load center basis. Many of the procedures now used by WAPDA for load forecasting were originally established during the course of this survey.

WAPDA set up its own Power Market Survey Organization in 1963 and annual reports have been published since that time—often with considerable delay—updating the load forecast and extending it one more year so as to maintain the five-year perspective. These surveys group energy consumption into seven main classifications: residential and commercial, small industry (less than 70 kw connected load), medium and large industry, agriculture, SCARPs (Government Salinity Control and Reclamation Projects), dam sites and losses. The loads are grouped on a divisional basis, again by load centers, and finally aggregated by grid systems to produce five-year forecasts of annual peak demand for each of the four main WAPDA service areas.

Small industrial loads are grouped with residential and commercial loads. Statistics on energy consumption by these classes of customer are available from WAPDA's regional revenue and subdivisional offices. Predetermined load factors ranging from 10 percent to 30 percent, higher for the wealthier and larger towns, are assigned to estimate peaks. Prospective small industrial loads are assessed on the basis of the installed capacity of existing prime movers used and energy calculated on the basis of an assumed load factor. The residential and commercial load of areas to be electrified in forthcoming years is estimated on the basis of graphs, originally prepared by Harza, showing some correlation between per capita usage of energy and size of settlement for different types of areas. Four of these so-called "Electric Use Potential" graphs are used and the load of a village which is to be electrified is read from the graph considered relevant to a place of its economic standing. Potential residential and commercial use is increased at 3 percent per annum for the years preceding electrification. All existing commercial and residential loads are raised by 8 percent, as an allowance for required voltage improvement, and then projected along with small industrial loads at a flat rate of 6 percent per annum.

Agricultural loads (both public and private, except for SCARPs) are grouped with medium and large industrial loads as being the larger individual loads. The Harza survey included interviews with tubewell owners. Information on agricultural sales is available at the subdivisional and regional revenue offices of WAPDA. Utilization factors of 25 percent are applied to private tubewells and 65 percent for public tubewells. An allowance is made for new tubewell connections on the basis of the capacity of the existing prime mover. Medium and large industries are visited by the Power Market Survey Organization and their existing peak demands, as well as total energy requirements, are relatively easily obtainable since WAPDA has installed demand meters for these consumers. Maximum load achieved on their own (industrially owned) generating equipment is used to indicate the probable demands of existing industries which are to be connected to the WAPDA system. Information about likely new industrial loads is obtained primarily from the various Government sanctioning agencies for industrial projects; it is checked with the industrialists in the field, but it is not clear how much judgment is applied in the inclusion of these loads despite the historical evidence that sanctioned industries sometimes never materialize and often come to fruition more slowly than initially anticipated. In the absence of specific information, existing industrial loads are also increased at a rate of about 6 percent per annum.

In the aggregation of industries and tubewells into settlements and of settlements into district totals various diversity factors are used and a 14 percent allowance for distribution losses is added to district totals. SCARPs are then added, including their own somewhat lower allowance for losses and a further 7 percent allowance is added for transmission losses. Further diversity factors are applied to bring loads up to the total estimated for each grid system (North, Upper Sind, Lower Sind, Quetta).

As regards Karachi, WAPDA has made no independent load forecasts there, but Karachi Electric Supply Corporation has been making short-term forecasts for a number of years, based mainly on negotiations with industrialists regarding prospective industrial loads and simple projections of the total residential/commercial load. Their forecasts use a somewhat larger number of categories than the WAPDA forecasts. A thorough survey of the Karachi power market was undertaken in 1963 by Zafar and Associates, a local consulting firm, in association with Laramore, Douglass and Popham of New York.

Since the load forecasts made by the utilities in West Pakistan are all relatively short term (not more than 10 years and, for WAPDA, generally only five years) it would be necessary to make some extrapolation in order to reach a load forecast of adequate dimensions for the purpose in hand. Such an extrapolation would be difficult. The classifications of load are so aggregated (besides being different between Karachi and the WAPDA system) that it would not be possible to link them with any of the categories used by the Planning Commission in its projections for West Pakistan. Experience of other countries is often a useful guide for load forecasts, but again the aggregation of such diverse categories in the WAPDA projec-

TABLE 2-1
GROWTH OF ELECTRICITY PRODUCTION AND DOMESTIC OUTPUT IN VARIOUS COUNTRIES SINCE 1929 AND IN THE POST-WAR PERIOD

Area and Country	Electricity Production Average Annual Growth Rates 1929–54	Electricity Production Average Annual Growth Rates 1948–64	Average Annual Growth in GDP 1951–64
	(%)	(%)	(%)
World	6.0	8.8	—
Africa	8.4	8.9	—
S. Africa	7.8	7.4	4.8
N. America	6.2	7.5	—
Canada	5.3 (29–53)	6.9	4.3
Cuba[a]	5.8	6.7	—
Dominican Republic[a]	16.0 (37–54)	14.7	5.1
Guatemala[a]	8.0 (37–54)	12.7	4.5
Jamaica[a]	12.5 (37–54)	13.9	6.6
Mexico	5.6 (37–54)	9.1	6.2
Puerto Rico[a]	16.0	13.4	7.3
U.S.A.	6.4	7.6	3.6
S. America	7.9	8.8	—
Argentina[a]	5.5	7.6	2.6
Bolivia[a]	10.0 (37–53)	4.5	—
Brazil	9.0 (39–53)	9.5	5.1
Chile	5.7 (29–53)	4.5	3.7
Colombia[b]	11.0 (37–54)	12.6	4.7
Asia	6.6	10.9	—
Ceylon[c]	11.0 (37–54)	12.1	3.1
Japan	6.0 (30–54)	10.7	9.0
Turkey	12.5 (37–54)	12.4	6.6
Europe (excluding USSR)	5.3	8.6	
Austria	5.3	8.8	5.4
Belgium	4.1	5.9	4.0
Czechoslovakia	6.2	9.5	6.0
Denmark	7.3	9.2	3.7
Finland	6.8	9.9	4.4
France	4.4	7.7	4.8
Greece[a]	10.0	13.6	6.6
Hungary	7.5 (30–53)	10.4	6.1
Iceland[a]	6.4	9.2	5.1
Ireland	12.0 (30–54)	9.9	2.4
Italy	5.0	7.9	5.6
Luxembourg	3.4 (37–54)	8.7	2.4
Netherlands	6.7 (37–54)	11.1	4.7
Norway	4.3 (30–54)	8.4	4.1
Portugal	8.0	11.7	5.1
Romania	7.7 (29–53)	15.4	10.0
Spain	5.8	10.4	6.0
Sweden	6.5	7.5	3.9
Switzerland	4.0 (37–54)	6.6	4.6
U.K.[a]	7.5	8.7	3.0
Oceania	7.7	8.4	—
Australia	7.4	8.8	4.0
N. Zealand	7.5	8.0	4.1

[a] Public service only.
[b] Public only—includes three principal enterprises.
[c] Government plants only.

Source: U.N. Statistical Year Book 1955.
U.N. Statistical Year Book 1966.
GDP Statistics—World Bank.

TABLE 2-2
AVERAGE ANNUAL GROWTH OF GDP AND ELECTRICITY PRODUCTION IN VARIOUS COUNTRIES 1951-59 AND 1960-64

Country	Electric Production 1960-64	GDP 1960-64	Ratios of Electric Growth to GDP Growth 1960-64
Argentina	7.0	3.1	2.3
Australia	8.8	4.3	2.1
Austria	6.4	5.3	1.2
Brazil	6.4	4.0	1.6
Canada	4.5	4.6	1.0
Colombia	12.1	4.7	2.6
Denmark	10.7	5.3	2.0
Dominican Republic	9.2	3.9	2.4
Ecuador	9.4	4.4	2.1
Finland	11.4	6.2	1.8
France	6.9	5.9	1.2
India	13.4	5.0	2.7
Japan	11.8	9.8	1.2
Mexico	10.0	6.6	1.5
Nicaragua	11.4	8.3	1.4
Nigeria	18.1	4.8	3.8
Pakistan	24.0	5.5	4.4
Panama	13.0	8.2	1.6
Paraguay	7.8	3.0	2.6
Peru	8.4	7.5	1.1
Philippines	14.2	4.3	3.3
Turkey	12.1	6.2	2.0
U.S.	6.4	4.0	1.6
Venezuela	11.4	5.0	2.3

Electricity Production—U.N. Statistical Yearbook 1966.
GDP—World Bank Survey Data and Indicators.

tions would make it very hard to make projections on this basis. About the only practicable basis for extrapolation would be the overall growth rate of electric energy requirements encountered in different countries as related to output growth. However, overall growth rates are the outcome of so many diverse forces operating in each country, many of them peculiar to the country in question, that it is difficult to infer anything very meaningful on such a global basis. Moreover, as Table 2-1 and Table 2-2, suggests, the experience of different countries is so varied—and the overall growth statistic gives no indication as to the causes accounting for the variation—that it is possible to prove almost anything on such a basis.

STONE & WEBSTER FORECASTING METHODS

Rather than adopt an approach of this nature Stone & Webster tried to develop load classifications which, within the limits of available sales records, had a firm historical base and were at the same time potentially compatible with the categories used in economic planning. In their classification of loads they also tried to distinguish between those with different technical characteristics (load factors, monthly distribution, time of day when peak occurs, etc.) so that the effects of different rates of growth in the various classes and of any likely changes in these technical characteristics on the shape of the overall system load curves could be identified. S&W used hypothetical 1965 figures as the basis for their load forecast rather than the actual sales figures for 1960–64 which were available to them because of the downward bias imparted to the actual figures by the load shedding and voltage reduction which took place in those years. In their 1965 base they also included small allowances for the loads which were at that time met by small independent utilities within the WAPDA service areas but which in future will be largely met by WAPDA.

S&W made forecasts of energy requirements in each of the four main electrical zones of West Pakistan (Northern Grid, Upper Sind, Lower Sind and Karachi) by class of service—residential, commercial, agricultural (public and private), industrial, public lighting, bulk and losses—for the key years 1970, 1975, 1980 and 1985. Annual hours of use were then assigned to each class of consumption in order to derive the peak demand of each class. Class demands were then totaled and a diversity factor was applied in order to obtain total area demand. Monthly energy requirements and peak loads were derived for the key years on the basis of the existing pattern of demand over the year and with attention to likely changes in the pattern resulting from the growth of tubewell load, gradually increasing use of air-conditioning and the diminishing relative weight of the industrial load. Loads were then interpolated between years to arrive at a detailed monthly picture of energy requirements and peak loads for each area for each month of the 20-year planning period. In all his calculations, the power consultant used loads net of station use, because station use differs so much between thermal plants (about 5 percent of capacity) and hydro plants (about 0.5 percent of capacity) that use of gross demands could lead to exaggeration in later years when the system is more heavily hydro based.

For the forecast of industrial loads S&W made use of the WAPDA and KESC files on existing industrial loads in the various areas and on sanctioned industries. S&W codified this material and evaluated it, making some allowances for delays in project execution where these seemed likely. For the longer term S&W was guided by the macroeconomic framework for the growth of West Pakistan provided by the Perspective Planning Section of the Planning Commission—which assumes a rather sharp falloff in the industrial growth rate—and by their own evaluation of the resource base and industrial climate of the different regions of West Pakistan.

The basis for S&W's residential load forecast was the 1960 Housing Census and a number of socioeconomic surveys of the major cities of West Pakistan and of some rural areas in the North. They adopted the housing unit (i.e. independent household—defined as a family or group of persons living together and eating from the same kitchen) as the basic building block of the residential load forecast. The number of housing units in existence in different areas in 1965 was projected on the basis of the 1960 Housing Census and the 1961 Population Census, differentiating between those in towns of more than 25,000 population[1] and those elsewhere. The proportion of houses currently connected in each area was estimated on the basis of the socioeconomic surveys and any other information available, as well as independent field checks. S&W assessed consumption per house on the basis of estimated residential sales of energy in 1965. From the base year of 1965, they proceeded in the same manner, estimating the number of houses there would

[1] According to the 1961 Population Census.

be in each of the key years 1970, 1975, 1980 and 1985, on the basis of population projections for those years, and then estimating the proportion of houses that might be expected to be electrified by each key year. The gradual growth of electricity consumption per house was also assessed on the basis of estimated use in 1965. Multiplication of the number of electrified houses in each area by the projected average annual consumption per house gave a figure for total domestic consumption in each area in each key year.

The basic material on the agricultural loads was prepared by IACA on the basis of drainage and crop-water requirements, a schedule of tubewell projects, and a pattern of integrated use of groundwater and surface water deduced from computer studies; for areas not covered by the public tubewell program they projected continuation of private tubewell development and a gradual increase in the proportion of private tubewells electrified. The irrigation engineers also determined pumping utilization factors for different types of wells in different areas in order to assess peak load per tubewell and estimated diversity factors to be applied in the aggregation of tubewell loads in an area. In order to reduce the system peak at critical times an allowance was made for interrupting tubewells during the four hour evening peak period. IACA revised its pumping projections substantially between the time that S&W submitted their report and completion of the Study; S&W prepared a revised pumping load forecast. The projections of tubewell load had been calculated on the basis of an early version of the groundwater program, covered in the irrigation consultants' computer analysis.

There are certain other existing and prospective loads which are either discrete items which S&W projected as such or classes which make up relatively small portions of the total load such as Public Lighting. Examples of the first are construction power for Mangla and Tarbela Dams, railway electrification and the load of the Wah Ordnance Factory. For public lighting S&W applied a rate of growth somewhat above that experienced in developed countries.

An important portion of WAPDA's total load in recent years has been transmission and distribution losses. It is estimated that, on the Northern Grid system, they rose from 15 percent of total energy generated in 1960 to a peak of about 22.5 percent in 1962. In 1964 they amounted to about 20 percent of energy generated. The power consultant estimates that part of these losses—mainly due to the bad state of the distribution system and illegal diversion of energy—can be eliminated by better management. Therefore, despite the greatly increased amount of long-distance transmission that will be involved in later years, he estimates that losses could fall to about 17.5 percent of total generation on the Northern Grid system by 1975 and to about 15.7 percent by 1985 and by similar amounts in the other WAPDA areas. They are already down to about 11 percent on the KESC system, but it does of course have the advantage of being much more compact.

Bank Study Group's Review of Stone & Webster's Forecasts

The results of the load forecasts which S&W prepared by application of these methods are indicated in Chapter VI of Volume One. The Study Group reviewed both the methodology and the results in considerable detail and found that they were generally good. Many assumptions had had to be made, but that was inevitable given the uncertainty of basic data and the absence of any detailed projections for the growth of the nonagricultural sectors of the economy. The classification used by S&W seemed appropriate, and the effort that they had made to develop forecasts of monthly loads on a common basis for the whole Province seemed to be a useful contribution to the process of load forecasting in West Pakistan.

In reviewing the projected loads finally adopted by S&W, the Study Group had in mind that a long-term forecast should, if anything, err on the optimistic rather than the pessimistic side so as to make sure that plans are made sufficiently far in advance to cope with the loads when they come. The Study Group came to the conclusion that the S&W load forecast generally met this criterion. The order of magnitude seemed reasonable. Studies undertaken by the Study Group attempting to link the load forecast to long-term economic development in West Pakistan suggested that the residential load projected by S&W might be slightly too great (because of the rapid rate of increase in consumption per household assumed) and also that the growth rate of industrial load adopted by S&W might be a little too high around the middle of the Perspective Plan period and a little too low at the end of the period. This meant that the forecast tended to the optimistic side. In addition to reviewing each of the various classes of load the Study Group also tried, as best it could, to evaluate the regional distribution of load projected by S&W. This was extremely difficult, because there was very little information available about Pakistan's intentions regarding regional development. A physical planning section of the Planning Commission was set up in recent years, but it remains a small body and it did not appear to have had the opportunity of devoting thought to the kind of long-term regional development trends relevant to load forecasting. The Study Group came to the conclusion, on the basis of what thin evidence it had, that, as far as could be seen, the growth of industry and particularly of power-intensive industry would, as S&W had projected, tend to be greater in the South than in the North of West Pakistan through the Perspective Plan period.

Future Load Forecasting in West Pakistan

Besides evaluating the S&W load forecasts, the Study Group also gave attention to the future of load forecasting in West Pakistan. It is essential that load forecasting be a continuous process, especially in the condition of dynamic economic growth that West Pakistan established during the Second Plan period. WAPDA recognized this with the establishment of its Power Market Survey Organization. The Study Group thinks that some of the procedures used by that organization, as implied previously, could be improved and it has therefore summarized some suggestions later in this Paper. In the course of its work the Study Group also adopted some approaches which it believes could be of use in future load-forecasting work in West Pakistan.

Contingency Load Forecasting

Given the uncertainties surrounding much of the basic data available in West Pakistan and inevitably relating to long-term projections into the future, the Study Group believes that it would be appropriate for WAPDA to work with more than one load forecast, especially when major decisions, such as regarding EHV transmission, are in question. The Study Group used the S&W forecast (adjusted for the revised IACA pumping forecast) as the Main Load Forecast for its studies but it also developed a Contingency Load Forecast, which was used in testing some decisions and would have been used more extensively had time been available. The Contingency Load Forecast relates to the Northern Grid area. There were a number of difficulties relating to this area. In the first place, despite the importance of the Northern Grid in the total power system of the Province, there is great uncertainty about the real magnitude of current loads. In most years of the Second Plan period there was a certain amount of load shedding and voltage reduction, and in 1965–67 this load shedding became quite acute, variously estimated for instance in December 1966 at between 100 and 200 mw. Later in 1967 and early in 1968 it should be possible to obtain a better reading of actual loads in the North than has been possible for some years; in the meantime uncertainty continues. In the second place, as explained in Chapter VI of Volume One, WAPDA/Harza, S&W and the Study Group appeared to be very largely in agreement on load forecasts except in the case of the basic (i.e. nonagricultural) load in the Northern Grid area. In the third place, there are some major uncertain factors regarding loads in the North, which could put them higher than projected by S&W. WAPDA allows a peak load for Tarbela construction power of about 80-85 mw against S&W's 50-55 mw. WAPDA also projects an increase of 15 mw in the load at the Wah Ordnance Factory (a load which S&W held constant) by 1970 and an increase of general industrial load by that date some 40-50 mw higher than projected by S&W. There are other potential new industrial loads in the North that could be important at later dates, such as a steel mill at Kalabagh and a plant to produce sulphuric acid from local gypsum for use in the manufacture of phosphatic fertilizer. The Study Group believes that its Main Load Forecast has sufficient margin to cover most of these possible developments, except the rather large additional loads projected by WAPDA for 1970. In general, however, there is uncertainty about the extent to which the transfer of Government from Karachi to Islamabad and the Government's emphasis on industrial development outside Karachi may result in greater growth than projected in the Main Forecast of large-scale commercial and industrial load in the North.

In face of these uncertainties regarding existing loads and likely growth of industrial and commercial loads in the North the Study Group adopted for its Contingency Load Forecast a projection of basic loads based on a trend prepared by Harza. S&W's load forecast has a sounder analytical base and seemed, on a Province-wide basis, to be on the optimistic side; as indicated previously, it was carefully built up item by item. The Harza trend is simply a rough extrapolation of load growth (from the base-year figures developed by S&W for 1965) at annual rates declining from 14 percent per annum during the Third Plan period to about 10 percent during the Sixth Plan period. It is approximately consistent with the projection of the Power Market Survey Organization for the Third Plan. The revised IACA pumping load was used in conjunction with both the S&W and the Harza forecasts of basic load. Table 2-3 shows the two forecasts. The Harza figures would seem to make ample allowance for the uncertainties discussed above. It ends with a basic load in 1985 some 50 percent higher than that used by S&W. The rough techniques underlying the Harza projection would seem to be adequate for a secondary Contingency Load Forecast and, in view of the difficulty of making predictions with any degree of precision in West Pakistan, the Study Group believes that WAPDA would be wise to prepare itself for different eventualities by using a number of alternative load forecasts.

TABLE 2-3
ALTERNATIVE LOAD FORECASTS FOR NORTHERN GRID AREA
(million kwh)

	1965	1970	1975	1980	1985	Annual Rate of Growth (%)
Main Forecast (Stone & Webster)						
Basic Load	1,820	3,100	4,600	7,040	10,270	9.0
Pumping Load	680	1,514	2,628	3,547	4,793	10.3
Total	2,500	4,614	7,228	10,587	15,063	9.5
Contingency Forecast (Harza)						
Basic Load	1,820	3,480	5,900	9,596	15,453	11.3
Pumping Load	680	1,514	2,628	3,547	4,793	10.3
Total	2,500	4,994	8,528	13,143	20,246	11.0
		Projected Peak Loads (mw)				
Main Forecast (Stone & Webster)	473	889	1,402	2,021	2,878	
Contingency Forecast (Harza)	473	967	1,591	2,521	3,928	

INTEGRATION OF LOAD FORECASTING WITH ECONOMIC PLANNING

Another aspect of load forecasting which merits serious attention from WAPDA and the Planning Commission is the integration and reconciliation of power load forecasts with general economic projections. All who have been connected with load forecasting in West Pakistan have strongly urged that it be more closely integrated with economic planning and forecasting. Harza pointed to the fact there are fairly definite relationships, for different types of industry, between their output and electric energy consumption. It recommended the collection of the requisite statistics for West Pakistan's industry and the development of relationships between economic parameters and loads. S&W attempted to develop such relationships, but without success. A fundamental difficulty at present is the dearth of reliable statistics even on the existing situation in the Province. Economic statistics, though still of very poor quality, are gradually being improved by the Central Statistical Office, Planning Commission and Government departments. Yet little attempt seems to have been made to gather power statistics in such a way that economic relationships could be developed to assist in future load forecasting even at the macroeconomic level. S&W recommend the establishment of a joint economic and power group to help in load forecasting. This is a priority need, and one of the first tasks of such a group should be to specify the uniform statistics required and to develop programs for their collection on a continuing basis.

To assist in the evaluation of the S&W load forecast and to help in the development of concepts linking economic planning and power planning, the Bank Group undertook some extensive exercises the results of which are summarized in this

Paper. Regarding industrial loads base year (1962/63) data were developed on value added and electricity consumption by industrial sector. The resultant sectoral power intensities (kwh consumed per Rs. 10 of value added) were inspected and adjusted and used to help in forecasting loads on the basis of projected sectoral growth of output. Special attention was devoted to industries which are heavy consumers of power, such as fertilizer and cement. With respect to residential loads, the Study Group tried to analyze some of the components of residential load growth—such as growth of demand by existing consumers, number of new consumers to be added in each plan period and their initial level of consumption—and to relate the movement of these components to anticipated changes in some economic variables like family income levels and income distribution. The Study Group believes that both these approaches could be developed into useful links between power planning and economic planning.

Reserve Generating Capacity Criterion

Another aspect of power planning in West Pakistan which merits attention is the supplement that is made to the forecast loads in order to provide adequate reserve generating capacity. A number of different approaches to this question have been adopted so far, but little serious study has been devoted to assessing what would be a correct reserve criterion in planning the expansion of the power system. In practice, the problem has not been very important in the past since the utilities have had enough difficulty expanding capacity fast enough just to keep up with the growth of load; also the existing power systems have been relatively small so that reserve generating capacity was not a major item from the financial point of view. Nevertheless the power crisis of 1966/67 can be seen partly as the result of failure to provide adequate reserve generating capacity in the Northern Grid. Moreover, the power system is now becoming large enough that reserve capacity will be a more important item financially. The subject also merits special attention because the advent of Mangla and Tarbela, with their tremendous fluctuations in capability over the course of the year, will greatly alter the nature of the power system. The Study Group has in fact adopted a somewhat stricter reserve criterion than Harza: 12 percent of thermal capability and 5 percent of hydro capability over and above peak loads in the 10-day period when hydro capability is at its lowest in the year, as compared with Harza's approach of calculating reserves on the basis of the second lowest 10-day period in the year and effectively allowing no reserves in the minimum 10-day period. The difference in practice is not as simple since Harza defines its loads without any allowance for tubewell interruption. The Study Group defines its loads net of interruption on public tubewells. Moreover, as pointed out above, the Harza forecast of basic load for the Northern Grid is substantially higher than the forecast used by the Bank Group and may therefore already allow for some of the uncertainties for which the Study Group makes supplementary allowance in its reserve criterion. What is clear is that neither of the two approaches is more than a rule of thumb.

With the completion of Mangla and the installation of increasing numbers of public tubewells there will be a number of additional factors to be taken into account in a serious study designed to identify an appropriate reserve criterion. So far attention has mainly been given to assessing the probability of outages of different durations on thermal equipment on the basis of past experience in West

Pakistan.[1] Much more attention will now need to be given to the effects of hydrological uncertainty, taking account of such things as the possibilities of maintaining higher minimum drawdown levels in years of above-average river flow and variations in the amount of energy required for pumping purposes under different conditions of surface water availability. Besides the hydrological aspects, the study of appropriate reserves should take into account a number of diverse factors such as the degree of certainty of the load forecasts (or the probability rating to be applied to each alternative forecast), delays encountered in securing spare parts or additional equipment as a result of the dependence on imports for supplies, the feasibility of rate agreements with selected large consumers with a built-in provision for contingent load shedding, the economic effects of unplanned load shedding, and the pressures that develop among industrialists who have experienced serious unreliability of utility power supply to purchase their own generating equipment. All of these factors must be considered within the context set by the facts that a very large proportion of energy will for the next decade be coming from what should be a highly reliable hydroelectric plant and that, on any reasonably foreseeable operation policy for Mangla reservoir, the period of minimum generating capability on the system should be of relatively short duration.

Summary Comments on Future Load Forecasting

The load forecast provides the essential frame of reference for system planning and is one of the main elements used in assessing the investment resources that should be allocated to the power sector. If West Pakistan is to develop a power system that is commensurate with its needs it is very important that the load forecasts used be soundly based and consistent with plans for the development of the rest of the economy. Some suggestions that arise from this Paper regarding the ways in which WAPDA's load forecasting might be strengthened are summarized below.

1. Procedures for the collection of statistics should be reappraised with a view to increasing the reliability of the figures gathered, the speed with which they are made available, and their relevance for load forecasting and system planning purposes. Loads should be classified in groups which are useful for planning purposes because the loads have similar technical characteristics or are found to be subject to similar forces of growth. For instance, commercial and residential loads should be considered separately from one another and so should public and private tubewell loads. Urban loads should be distinguished from rural loads, where possible. The categories should be compatible with categories used in economic planning.
2. Load forecasting should be coordinated with economic planning and forecasting to a much greater extent than it is now. This should be done not only on a Provincewide basis but, to the extent possible, on a regional basis, taking into account trends and plans for the growth of different sectors of the economy in different parts of the Province.
3. WAPDA load forecasting and system planning should be coordinated with similar work in KESC. This will involve agreement on the types of statistics to be collected and the statistical classifications to be used in projections. Long-term

[1] See, for instance, the interesting paper by A. Rahimtoola, "WAPDA Northern Grid System: Determination of Firm Generating Capacity" (October, 1966).

planning can only be performed effectively on a Provincewide basis. At present there appears to be duplication of effort, KESC planning to have sufficient capacity to meet Hyderabad loads for instance and WAPDA still planning on the assumption that it will have to have sufficient capacity in its systems to meet the same loads.

4. Load forecasts should be clearly related to past trends, analyzed on the basis of the statistical concepts and categories referred to in (1) above.

5. Services concerned with the collection and analysis of statistics and with load forecasting should be strengthened so that the results of their work are made available to management for decision-making purposes as soon as possible.

6. More attention should be given to the time pattern of loads, both the daily pattern of loads and different classes of loads in different areas and the monthly pattern of loads. Likely changes in these patterns should be analyzed. This will become important as the system expands and as more of the generating capacity on the system is of the multipurpose hydroelectric type with its capability fluctuating over the course of the year. Statistics and analyses of this type will be very valuable for efforts to make best possible use of the capacity and energy that will be available and to select appropriate pricing policies. Detailed daily load data are also needed in the near future in connection with decisions regarding interruption of the tubewell load.

7. Many of the rules of thumb used by the Power Market Survey Organization in forecasting loads—for instance regarding load factors and rates of growth of different classes of load—still appear to be based on assumptions first made several years ago. Empirical data should be collected and analyzed to see whether these assumptions are in fact correct. The rate of growth that is assumed to characterize residential load, for instance, seems low.

8. A range of load forecasts of different durations and with differing amounts of regional detail are required rather than the single 5-year load forecast now prepared. It may be that the detailed town-by-town and district-by-district analysis now used for the 5-year forecast is not needed quite so far ahead. It does seem that there will be increasing need for a very detailed two-three year load forecast, specifying loads by towns and districts and by much shorter periods than the whole year now used; this will be important for distribution-line work, decisions regarding system operation, etc. A solidly based 10-year forecast, with details for the main regions of the Northern Grid and for the Sukkur and Hyderabad systems, together with some estimates with an analytical basis regarding the trend in the monthly pattern of loads, seem necessary for adequate planning of the large investments now being considered. A more global 20-year estimate, still using classifications of load rather than aggregate system peaks, and somewhat similar to S&W's projection in methodology, would seem appropriate to indicate the longer-term perspective.

9. Important decisions should be made on the basis of analyses with more than one load forecast, given the uncertainty that inevitably surrounds long-term projections.

10. The approach that should be taken to reserve generating capacity in planning system development needs a thorough appraisal in light of the new conditions that will come into being as units are installed at Mangla and an increasing share of the total load is for pumping purposes.

The Industrial Load

THE STONE & WEBSTER INDUSTRIAL LOAD FORECAST

Stone & Webster projected an increase in the amount of electricity consumed in the industrial sector of the economy, including industrial self-generation, from about 1,600 million kwh in 1964 to about 13,500 million kwh in 1985. Growth of industrial consumption is expected to average about 10.5 percent over the 20 years, 1965–85, but it is expected to be substantially higher in the early years, averaging 13.0 percent per annum during the Third Plan period. Growth was about 10 percent per annum over 1960–64, when growth may have been held back to some extent by shortage of generating capacity. The industrial load on the public utilities has of course been growing at a much more rapid rate—above 16 percent per annum—as more industries have been transferring to supply from the public utilities. Annex Table 2.1-1 summarizes the S&W industrial load forecast by areas, and Appendix Table 2.1-1 compares these figures with the growth achieved between 1960 and 1964 in the different areas.

The power consultant projected a particularly rapid rate of growth of industrial consumption of electrical energy in Karachi—largely due to their assumption that a number of relatively power-intensive industries such as petrochemicals, steel, and oil-refining will be established there. They also anticipate a very rapid rate of

ANNEX TABLE 2.1–1
STONE & WEBSTER'S INDUSTRIAL LOAD FORECAST
(mill. kwh)

	1965	1970	1975	1980	1985	Annual Growth %
Northern Grid[a]	820	1,410	2,270	3,480	5,030	9.5
Upper Sind	10	145[b]	220[c]	300	409	20.0
Lower Sind	83	204	420	720	1,130	14.0
Karachi	355	850	1,750	2,950	4,440	13.5
Quetta	3	14	24	40	60	16.1
Self-generation	544	650	915	1,000	1,103	3.6
Karachi Petrochemical	—	130	480	920	1,390	
Subtotal	1,815	3,403	6,079	9,410	13,562	10.5
North: Dam sites	138	220	30	—	—	
Total	1,953	3,623	6,109	9,410	13,562	

[a] Excludes consumption at dam sites but includes an annual item of 30 million kwh which the power consultant estimated as the past and future supply of the Wah Ordnance Factory and included in the Bulk classification.

[b] Estimate assumes WAPDA would serve Esso fertilizer factory in 1970 with 100 million kwh at maximum load of 15 mw.

[c] Forecast based on power consultant's anticipation of substantial expansion in the fertilizer, cement, textile and food processing industries.

growth of the industrial load in the Upper Sind (Sukkur area); a comparatively slow rate of growth is anticipated in the North, where it is assumed that industry would be predominantly concerned with processing agricultural commodities and producing consumer goods. As already noted, the Study Group's evaluation of S&W's projection of the regional distribution of industrial load suggests that it is reasonable, as far as can now be foreseen. A case could be made for a somewhat slower rate of load growth in Karachi and in the Northern Grid, especially in the early years, but the load growth in Upper Sind may be even more rapid than projected by the power consultant if sufficient investment in the nitrogenous fertilizer industry is made.

Detailed Evaluation of Industrial Load

In evaluating the S&W load forecasts, the Study Group attempted to develop relationships between industrial value added (i.e., the gross output of an industry net of purchased inputs) and industrial consumption of electricity. An analysis was made of the present power-intensity of different industries in West Pakistan (i.e., kwh consumed per rupee of value added). With adjustments for any anticipated changes in the power-intensity of different industrial sectors, projections could then be made of electricity consumption that might be expected to accompany any particular pattern and rate of future industrial development.

The overall power intensity of industry in a country is heavily affected by the relative weight in total industrial production of a few industries which consume large quantities of power per unit of output. Aluminum, for instance, and paper, cement and certain chemicals, tend to be very power-intensive, and the growth of industrial consumption of electricity will be greatly influenced by the pace at which such industries are growing.

In general, as might be expected, industrialized countries consume considerably more electrical energy per unit of value added in industry than do low and middle income countries. Annex Table 2.1-2 shows some estimates recently made, for a number of countries, of growth rates and consumption in terms of dollars of value added per kwh consumed in industry. Pakistan ranks quite low in this list at a level of 1.1 kwh per dollar of value added. However, Pakistan's growth rate for electric consumption has been among the highest, as has its growth of industrial output. [The table is based on conversion into U.S. dollars at current official exchange rates.]

The evidence presented below for West Pakistan suggests that power consumption per dollar of value added is significantly higher than the estimate for Pakistan in Annex Table 2.1-2 would imply. However, no great significance should be attributed to this fact, since the figures are based on quite different sources and somewhat different concepts.

Existing Pattern of Industrial Consumption of Electricity

To obtain a better understanding of the actual composition of the industrial consumption of power in West Pakistan, the Study Group developed a table of industrial power intensities on the basis of information supplied by the Planning Commission and other material gathered by the power consultant. This table indicates the estimated amount of power consumed by each industrial sector in the

ANNEX TABLE 2.1-2

ANNUAL GROWTH IN ELECTRICITY PRODUCTION (1948-60), GROWTH IN INDUSTRIAL OUTPUT (1950-60) AND INDUSTRIAL CONSUMPTION OF ELECTRICITY IN KWH PER DOLLAR OF GNP IN MANUFACTURING (1955 AND 1961)

Industrial Countries[a]	Annual Growth in Electricity Production	Growth in Industrial Output	Industrial Consumption in Electricity in kwh per dollar of GNP in manufacturing	
	1948-60	1950-60	1953	1961
Luxembourg	8.5	3.0	7.5	5.6
West Germany	10.7	9.7	3.3	2.6
Austria	9.6	7.1	4.4	3.1
United Kingdom	9.1	2.5	2.5	2.5
Netherlands	9.5	5.3	2.6	1.7
Argentina	7.2	4.3	1.0	1.0
South Africa	7.7	4.0[b]	5.3	8.3
Belgium	5.3	3.2[c]	3.4	3.2
Israel	16.7	7.4[b]	1.4	2.2
United States	7.9	3.7	2.7	2.8
Portugal	12.2	7.2[c]	1.5	2.2
Congo (Leopoldville)	17.5[d]	6.7	3.6	9.0
Denmark	8.7	3.7	1.5	0.8
Italy	8.0	7.9	4.2	3.1
Japan	10.3	16.8	8.6	5.4
Norway	8.2	4.3	15.2	16.1
Finland	9.4	6.1[b]	5.0	5.3
Ireland	10.1	2.6	1.1	1.2
Mexico	8.7	7.0	2.5	1.6
Nonindustrial Countries[e]				
Chile	3.8	3.9	3.5	5.0
Brazil	10.6	9.0	1.5	2.7
Jamaica	14.0	1.37	0.4	3.4
Peru	13.0	8.0	1.0	4.9
Colombia	12.8	6.4	0.6	2.2
Greece	12.5	8.0	1.9	1.9
Ecuador	11.5	5.2	0.9	1.1
Philippines	12.6	9.2	0.8	2.0
India	11.1	3.6	1.2	2.8
Paraguay	8.3	1.5	0.7	0.5
UAR	n.a.	8.9	3.4	4.7
Turkey	12.6	5.9	1.6	2.0
Burma	24.5	13.6	0.3	1.4
New Zealand	10.3	4.9[b]	n.a.	n.a.
Panama	10.3	5.7	0.7	0.5
Guatemala	13.3	4.5	0.4	0.8
Lebanon	14.1	n.a.	1.5	n.a.
Thailand	20.5	6.6	0.5	0.8
Pakistan	22.0	8.0	0.5	1.1
Ceylon	14.5	8.9[c]	1.0	1.4

[a] Countries with 30 percent or more of total income generated by industrial and mining sector.

[b] 1949-57.

[c] 1956-60.

[d] 1948-59.

[e] Countries with less than 30 percent of total income generated by industrial and mining sector.

Source: Calculated on the basis of data taken from the U.N. Statistical Yearbook, 1956, 1966 and the Statistical Yearbook of the World Power Conference No. 8.

base-year 1962/63 and the estimated output of each sector (in Rs. million at factor cost). The Table is given in detail as Appendix Table 2.1-2 and it is summarized here in Annex Table 2.1-3. The last column of the Table indicates the power-intensity of each industry in terms of kwh consumed per Rs. 10 of value added. As expected, certain industries such as cement and fertilizer stand out as being extremely power-intensive, others such as paperboard, textiles and certain chemicals are moderately power-intensive, while other industries such as tobacco and cotton-ginning use relatively little electric power per unit of output. The relative order of magnitude of these results for different industries corresponds approximately to what might be expected from other countries' industrial experience. There are some cases—such as refining and some of the intermediate good sectors —where the power consumption figures seem unreasonably low and others where they are probably high.

On the whole, the figures of industrial consumption of electricity given in Annex Table 2.1-3 seem low, although a much more detailed comparison would be necessary to draw any conclusion. Annex Table 2.1-4 shows estimated sales of electric power to industrial consumers in the fiscal year 1962/63. There is a sizeable discrepancy between the estimates of total industrial consumption of electricity given in Annex Tables 2.1-3 and 2.1-4. This is to be expected because Annex Table 2.1-3 is based on results of surveys of industrial consumers while Annex Table 2.1-4 is based on the accounts of the electric utilities, which are kept in a form which does not readily indicate the nature of the ultimate electricity consumer. The survey results may be underestimates, because power consumption figures have been used in Pakistan in the taxation of industrial enterprises. The estimates in Annex Table

ANNEX TABLE 2.1-3
ESTIMATED INDUSTRIAL VALUE ADDED AND ELECTRICITY CONSUMPTION, 1962/63

Sector	Value Added (Rs. mill.)	Electricity Consumption (mill. kwh)	Power Intensity (kwh/Rs. 10 value added)
Sugar	187.8	29.177	1.55
Tobacco	45.0	3.989	0.89
Textiles (80%)	412.6	253.778	6.15
Board, Paper	22.9	7.331	3.20
Other Consumer Goods	501.6	91.236	1.82
Total Consumer Goods	1,169.9	385.511	3.30
Rubber	8.2	1.265	1.54
Fertilizers	42.2	136.640	32.38
Cement	53.0	148.112	27.95
Textiles (20%)	103.2	63.444	6.15
Cotton-Ginning	117.3	5.472	0.47
Chemicals and Refining	85.9	15.412	1.80
Other Intermediates	78.3	25.572	3.26
Total Intermediates	488.1	395.917	8.10
Investment Goods	334.0	110.905	3.32
Total Large-Scale Mfg.	1,992.0	892.333	4.48

ANNEX TABLE 2.1-4
ESTIMATED INDUSTRIAL SALES OF ELECTRICITY AND SELF-GENERATION, 1962/63
(mill. kwh)

WAPDA—Industrial Sales[a]	664
Deduction: estimated consumption at dam sites	20
	644
KESC—Industrial Sales[b]	208
Industrially owned generation[c]	535
Other utilities' industrial sales[c]	41
Total	1,428

[a] Taken from WAPDA's annual reports, and including 30 million kwh for Wah.
[b] Interpolated from KESC's recorded sales (calendar-year basis).
[c] Estimates from the power consultant's report and Central Statistical Office, Census of Electricity Undertakings 1962/63.

2.1-2 do cover several important classes of consumer not included in Annex Table 2.1-3. The mining industry, for one, consumed at least 20 million kwh in 1962/63 (mainly self-generated). More important still, small-scale industry and numerous other semi-industrial establishments (such as sewerage and water supply pumping stations, Irrigation Department Workshops, airports, etc.) are covered by the figures given in Annex Table 2.1-4 but not by those given in Annex Table 2.1-3. Small-scale industry and other establishments probably account for 200 million kwh out of the total of 1,428 million kwh listed in Annex Table 2.1-4 as industrial consumption in 1962/63.

Deduction of these items from estimated industrial consumption in 1962/63 leaves an estimate of 1,210 million kwh as consumption in the large-scale industrial sector in the base year. This is still about 320 million kwh above the figure given in Annex Table 2.1-3. It is likely that the most serious undercounting in the survey figures occurs in the consumer goods sector, where there are many small industrial establishments. However, to make sure that the figures used include an adequate allowance for the higher power intensity of the intermediate goods and capital goods sectors, which are expected to grow more rapidly than consumer goods industries in coming years, the difference of 320 million kwh has been distributed in proportion to the recorded consumption of electricity of the various sectors.[1] Annex Table 2.1-5 summarizes the adjusted estimates of power-intensity

[1] Including the nitrogenous fertilizer industry, for which the recorded figures on electricity consumption are already inexplicably high. The Multan plant has a capacity of 59,000 tons of urea and 103,000 tons of calcium ammonium nitrate. The highest electricity consumption that could reasonably be expected for this plant, if it were working at full capacity, is about 76 million kwh (including an allowance for off-site facilities)—or about 1,400 kwh per ton of nitrogen. Full capacity represents about 54,000 tons of nitrogen-equivalent fertilizer. Actual production was about 30,000 tons of nitrogen in 1962/63 when recorded power consumption was 77 million kwh, while in 1963/64 production was about 34,000 tons of nitrogen and recorded consumption of electricity about 101 million kwh. The Daudkhel ammonium sulphate plant has a capacity of 10,500 tons of nitrogen-equivalent fertilizer (50,000 tons of ammonium sulphate) and appears to have been running close to capacity in recent years. Anticipated electricity consumption at 500 kwh per ton of N would be 5.5 million kwh. The plant generates its own electricity and was estimated to have produced 54.0 million kwh in 1962/63.

ANNEX TABLE 2.1-5
LARGE-SCALE MANUFACTURING IN WEST PAKISTAN
ESTIMATED POWER INTENSITIES, 1962/63

	Value Added	Power Consumption (mill. kwh)		Power Intensity
		Reported	Adjusted	
	(Rs. mill.)			(kwh/Rs. 10 value added)
Capital Goods	334	111	151	4.52
Consumer Goods	1,170	386	525	4.49
Cement, Concrete	53	148	201	37.92
Nitrogen Fertilizer	42	137	186	44.28
Other Intermediates	393	111	151	3.84
	1,992	892	1,214	6.10

by major industrial grouping, separating out from the intermediate goods sector the highly power-intensive nitrogenous fertilizer and cement industries.

To check the validity of the sectoral power-intensity approach to the projection of the industrial load, and to see how power-intensities of the major industrial groupings are changing, estimates were made of the sectoral growth of value added between 1962/63 and 1964/65. Consumption of electricity by major sectors was then estimated on the assumption that power-intensities of each individual industry remained the same. The detailed projection is presented in Appendix Table 2.1-3 and a summary for comparison with Annex Table 2.1-5 is given in Annex Table 2.1-6. The 'adjusted' column of figures in this table was derived by multiplying the figures estimated on the basis of growth of value added by the same ratio (1.36) as was used to "gross-up" the figures for 1962/63.

Assuming constant power intensities in the mining and small industry sectors, consumption by these sectors would have been about 24 million kwh and 210

ANNEX TABLE 2.1-6
LARGE-SCALE MANUFACTURING IN WEST PAKISTAN
ESTIMATED POWER INTENSITIES, 1964/65

	Value Added	Power Consumption (mill. kwh)		Power Intensity
		Reported	Adjusted	
	(Rs. mill.)			(kwh/Rs. 10 value added)
Capital Goods	507	169	230	4.53
Consumer Goods	1,408	499	680	4.82
Cement, Concrete	56	156	212	37.90
Nitrogen fertilizer	29	93	126	44.30
Other Intermediates	670	173	235	3.50
	2,670	1,090	1,483	5.55

ANNEX TABLE 2.1-7
ESTIMATED INDUSTRIAL SALE OF ELECTRICITY AND SELF-GENERATION, 1964/65
(mill. kwh)

WAPDA—Industrial Sales[a]	932
Deduction: Estimated Consumption at Dam Sites	120
	812
KESC—Industrial Sales[a]	325
Industrially Owned Generation[a]	544
Other Utilities' Industrial Sales[a]	45
Total	1,726

[a] Footnote same as to Annex Table 2.1-4.

million kwh respectively in 1964/65. Addition of these to the 'adjusted' total in Annex Table 2.1-6 would suggest that total industrial consumption of electricity in 1964/65 must have been about 1,717 million kwh.

Actual sales of the utilities to industry, together with industrial self-generation in 1964/65, are estimated as shown in Annex Table 2.1-7. Thus the two estimates of industrial consumption of electricity appear to check out quite well with one another. The difference between 1,717 and 1,726 is well within the margin of error.

PROJECTION OF ELECTRICITY CONSUMPTION IN CEMENT AND FERTILIZER INDUSTRIES

The cement and fertilizer industries were shown above to be among the more power-intensive industries in Pakistan, as elsewhere. For this reason and because both industries, particularly nitrogenous fertilizer production, are likely to grow quite rapidly in coming years, they were separated out and projected individually. Projections of production of cement and fertilizer were made on the basis of the Bank's report, "The Industrial Development of Pakistan" (June 7, 1966), and with due regard to conclusions reached in other parts of this Study about fertilizer production and consumption.[1]

Detailed projections of fertilizer and cement production and electricity consumption by these industries are shown in Appendix Tables 2.1-4 to 2.1-6. The physical levels of output projected for 1970 are not quite the same as those given in the Third Plan document in the case of cement; production is here projected at 3.5 million tons in 1970, as compared with the Third Plan target of 4.0 million tons. Nitrogenous fertilizer production is here projected at 250,000 tons of nitrogen equivalent, which is about the same as in the Third Plan document of June, 1965. The shortfall in cement arises from delays that have been encountered in getting underway some of the projects which are to produce the expected output increases.

In Volume Two, the Study Group presents targets of fertilizer absorption which are substantially above those selected by the agriculture consultant, but somewhat below the targets adopted by the Government of Pakistan. If farmers do show a more rapid response to fertilizer than presently anticipated, and if the transport and fertilizer-distribution systems can be improved rapidly enough to handle much larger quantities, then it would be fully worthwhile to ensure that the requisite

[1] See Volume Two.

ANNEX TABLE 2.1-8
PRODUCTION AND CONSUMPTION OF NITROGENOUS FERTILIZER
(nutrients/thousand tons)

	1965	1970	1975	1980	1985
Production[a]	65	250	560	790	1,020
Consumption[b]	90	250	470	540	620

[a] From Appendix Table 2.1-5. [b] From Volume Two.

amount of fertilizer is available. The Study Group's targets for the absorption of nitrogenous fertilizer are compared in Annex Table 2.1-8 with the projection of nitrogenous fertilizer production assumed for purposes of this analysis of power requirements. Thus the production assumptions made here fully cover the consumption projected in Volume Two. The objective here was to make ample allowance for any unanticipated growth in demand and also for the possibility that export of fertilizer will become attractive.

Requirements of electricity for production of fertilizer and cement are estimated in Appendix Table 2.1-6, which details the assumptions made. It is important to note that the effective power-intensity of fertilizer production will probably decline markedly in coming years, partly because the existing fertilizer plants appear to be consuming much greater quantities of electricity than modern equipment should require, and partly because the large-scale fertilizer plants that are planned for the future should be able to meet a large proportion of their own energy requirements through the use of process steam. Annex Table 2.1-9 summarizes the projection of electricity requirements for production of cement and fertilizer.

ANNEX TABLE 2.1-9
ELECTRICITY REQUIREMENTS FOR PRODUCTION OF CEMENT
AND NITROGENOUS FERTILIZERS
(mill. kwh)

	1965	1970	1975	1980	1985
Cement	212	520	700	960	1,320
Fertilizer	126	360	516	610	700

INDUSTRIAL GROWTH IN THE PERSPECTIVE PLAN

The long-term growth framework provided by the Planning Commission and discussed in greater detail in Supplemental Paper No. 1, implies that the West Pakistan gross provincial product will grow at an average rate a little above 6 percent per annum over the period 1965–85. Agriculture is expected to make a very substantial contribution to this overall growth rate. Large-scale industry is expected to grow at an average rate of about 8 percent or, in other words, somewhat more rapidly than the total provincial product. This would be a reversal of the situation during the Second Plan period (1960–65) when the industrial sector grew substantially faster than GPP. Constant-price estimates suggest that, between 1959/60 and 1964/65, GPP grew at an average rate of nearly 6 percent per annum, output of the manufacturing sector at about 11.5 percent per annum, and output of the large-scale manufacturing sector at about 16 percent per annum.

Despite the apparent undue pessimism of the Perspective Plan with regard to the industrial growth rate in West Pakistan, an initial projection of industrial power load was made, consistent with the specific projections made above for cement and fertilizer and with a framework of industrial growth believed compatible with the expectations of the Planning Commission. This framework is presented in detail in Appendix Table 2.1-7. It was found that industrial consumption of electricity might, on this basis, be expected to grow from about 1,720 million kwh in 1964/65 to about 3,800 million kwh in 1974/75, and about 7,700 million kwh in 1984/85—or, in other words, at an average rate of about 7.8 percent per annum, slightly more before 1975 and slightly less afterwards.

This projection was made on the assumption of constant power-intensities in all sectors except fertilizer. Powered consumption had been projected on the basis of the highly aggregated sectors (shown in Appendix Table 2.1-7) such as consumer goods manufacturing, capital goods, small industry, etc. There appeared to be no particular reason for anticipating a substantial increase of power-intensity in the capital goods and consumer goods sectors. Major capital goods industries are expected to be established in West Pakistan, including heavy electrical machinery, textile machinery and transport equipment; but the ratio of value added to consumption of electrical energy tends to be relatively high in those industries, and the overall power-intensity of the sectors might decline slightly rather than increase. In the intermediate goods sector, on the other hand, some major industries are expected to come into Pakistan which are qualitatively different from existing plants in this sector in the Province. Annex Table 2.1-3 showed that the average power-intensity in the intermediate goods sector (excluding fertilizer and cement) is at present exceptionally low. This results mainly from the predominant position of the cotton-ginning industry in the sector and from the fact all the other industries in the sector have comparatively low power requirements. Two important additions to this sector during the next 10 years will be considerably more power-intensive.

Petrochemical Industry

A very ambitious plan has been prepared by consultants for the construction of a major petrochemical industry in West Pakistan, concentrated in the Karachi area. This petrochemical complex would be based, in the first instance, on a naphtha cracker producing naphtha and ethylene. A World Bank industrial mission has endorsed the project and recommended that West Pakistan concentrate its efforts in the petrochemical field on products that can be made as derivatives of the steam cracking unit. Stone & Webster have made an allowance for the power requirements of the petrochemical complex, considerably smaller than the projections that had been made by others but more in line with the actual likely growth of the petrochemical industry and rising to substantial levels in later years. The most recent information available to the Study Group on this project is presented in Appendix Table 2.1-8. The S&W allowance for the electricity requirements of the petrochemical complex is somewhat below the estimates given there for the early period and somewhat above them for later years.

Steel Industry

Another major potential development in the intermediate goods sector that could substantially affect sectoral electricity consumption is the construction of one or possibly two steel mills. A steel mill at Karachi has been under consideration for more than a decade. Due to delays, in the early years of the Third Plan, it will not be possible to have this plant completed by 1970. One plan is for a mill based on electric arc furnaces, which would use local and imported scrap to produce billets, rails, tubes and sheets. Capacity would be in the neighborhood of half a million tons of finished product per annum. If the plant comes into operation in Karachi in the early 1970's, as projected, its large power requirements will be too fluctuating for it to depend entirely on KESC. However, KESC would probably supply a gradually increasing proportion of its requirements. A further possible development in this sector is establishment of a steel mill based on local ore at Kalabagh. West German consultants have suggested that the Kalabagh ore might be recovered economically, despite its low ferrous content, by application of a new process. Implementation of either of these projects remains a matter of uncertainty, but some allowance should be made for their potential power requirements in the slightly longer term.

Estimates of the power requirements of these two industries, based mainly on the views of S&W, are given in Annex Table 2.1-10. Formal consistency would require some compensating reduction in the industrial load forecasts made on the basis of constant power-intensity, before these loads are included as allowance for extreme power-intensity of anticipated new plants. However, the contribution of the "Other Intermediates" sector (i.e. intermediate goods excluding fertilizer and cement), in which grouping these industries fall, to the load forecast is relatively small and the power-intensity upon which it is based is so low that it seems permissible simply to add these loads to those derived on the macroeconomic base.

"Perspective Plan" Industrial Load Forecast

Addition of these special loads to those derived on the basis of the Perspective Plan framework would lead to estimates of about 4,600 million kwh in 1975 and about 10,500 million kwh in 1985 for the industrial consumption of electricity. Comparison of these figures with those given in Annex Table 2.1-1 indicates that the estimates derived from the Perspective Plan are substantially below those made by S&W.

A Higher Industrial Growth Rate?

As pointed out above, the industrial growth rate implicit in the Perspective Plan seems low by comparison with past performance in West Pakistan. Some elements of the growth pattern—such as the very low rate of growth projected in the consumer goods industry—also seemed to represent projections from which there

ANNEX TABLE 2.1-10
Energy Requirements of Petrochemical Complex and Steel Mills
(mill. kwh)

	1970	1975	1980	1985
Petrochemical Complex	360	560	780	1,390
Karachi Steel Mill	—	100	400	800
Kalabagh Steel Mill	—	150	300	600
Total	360	810	1,480	2,790

ANNEX TABLE 2.1–11
LARGE-SCALE MANUFACTURING INDUSTRY, 1965–85[a]
(Rs. million, 1962/63 prices)

	1965		1970		1975		1980		1985
Capital Goods	507	(20.0)	1,250	(14.2)	2,450	(10.7)	4,050	(8.9)	6,200
Consumer Goods	1,408	(6.0)	1,900	(6.0)	2,550	(5.5)	3,300	(5.5)	4,300
Intermediate Goods	755	(16.3)	1,600	(15.0)	3,230	(10.0)	5,200	(8.9)	8,000
Of which:									
Fertilizer (nitro)	29		157		345		487		640
Cement	56		116		158		216		310
Other Imtermediates	670		1,327		2,727		4,497		7,050
Total	2,670	(12.2)	4,750	(11.6)	8,230	(8.8)	12,550	(8.0)	18,500
			Electricity Consumption (mill. kwh)						
Capital Goods	230		566		1,110		1,840		2,810
Consumer Goods	680		920		1,230		1,600		2,100
Fertilizer (nitro)	126		360		516		610		700
Cement	212		520		700		960		1,320
Other Intermediates	235		460		950		1,570		2,460
Total	1,483	(13.7)	2,826	(9.8)	4,506	(8.0)	6,580	(7.5)	9,390

[a] Figures in parentheses represent annual growth rates of the relevant sectors during the Plan periods in which they are inserted.

might in practice be some divergence. Therefore, it appeared useful to test the implications of an alternative forecast of industrial growth in West Pakistan. This pattern, which differs from the "Perspective Plan" growth path primarily by allowing more rapid growth of consumer goods industries, and hence of overall industrial production, is shown in Annex Table 2.1-11. The lower half of the table indicates the power requirements, that this pattern of industrial development would imply, assuming constant power-intensities (except in the case of fertilizer). Addition to the totals of appropriate allowances for the growth of mining and of small industry and for the special petrochemical and steel projects (discussed in previous paragraphs) leads to the estimate of the growth of industrial consumption of electrical energy presented in Annex Table 2.1-12.

ANNEX TABLE 2.1–12
PROJECTED INDUSTRIAL REQUIREMENTS FOR ELECTRICAL ENERGY WITH HIGH INDUSTRIAL GROWTH RATE
(mill. kwh)

	1965	1970	1975	1980	1985
Large-Scale Industry	1,483	2,826	4,506	6,580	9,390
Steel and Petrochemicals	—	360	810	1,480	2,790
Mining	24	40	60	90	130
Small Industry, etc.[a]	210	234	274	370	490
Total	1,717	3,460	5,650	8,520	12,800
Stone & Webster Forecast[b]	1,815	3,403	6,079	9,410	13,562

[a] With allowance for increasing conversion to power-driven equipment in later years of the Perspective Plan.
[b] Excluding power for dam sites.

CONCLUSION

In very general terms, the conclusion to be drawn from the Study Group's analysis is that the S&W forecast of industrial load may be somewhat on the high side for most of the period under study. The rapid rate of growth projected by S&W for the Third Plan period may be attained, if progress is as rapid as here assumed, particularly in the power-intensive industries such as nitrogenous fertilizer, petrochemicals and cement. Thus, during the Third Plan, total industrial consumption of electricity may well grow more rapidly than total industrial output —in contrast to the Second Plan when total industrial load appears to have grown about 10 percent per annum and industrial output (including small industry) about 13 percent per annum. During the Fourth Plan period, the growth of industrial demand for electricity may slow down somewhat as the growth of industry stabilizes and agriculture grows more rapidly, and as some of the most power-intensive industries (such as fertilizer) take advantage of modern techniques which involve much less purchase of electricity from outside and much more generation from process steam. The same trend might continue through the Fifth Plan period.

REGIONAL DISTRIBUTION OF LOAD GROWTH

Regarding regional distribution, the economic studies undertaken in the Bank tend to confirm the general judgment of S&W, that the load will grow more rapidly in future in the South—Karachi and the Sind—than in the area where it is at present larger, the North. As main reasons for this, there are few power-intensive industries presently foreseeable in the North; Karachi, on the other hand, has all the advantages of being the major port of the country and having the relatively highly developed industrial infrastructure which is most crucial to the success of modern complex industry; the Sind has the advantage of its extensive natural gas resources—and also a convenient location relatively close to the port of Karachi and midway between the country's major markets: the Punjab on the one hand and Karachi and the export market on the other. This is not to say that industrial development will be slow in the North but that it will be mainly concentrated in consumer goods industries and agricultural processing industries which are not typically major consumers of power. Even the machinery complexes planned for the North do not compare in their power requirements with some of the major industries planned for the South.

Within the South itself, there might be some redistribution of the loads projected by S&W. For instance, they allow a growth of industrial load in Upper Sind barely sufficient to meet the demands for purchased power that may arise from the fertilizer industry there. On the other hand, they have allowed high growth rates for the more established industrial area around Hyderabad and some of the fertilizer production might take place there, depending on the choice of gas field for use in fertilizer production and on the extent to which economics make it mandatory to locate production on the gas field itself. The petrochemical load which S&W projects for Karachi appears a little high for the 1980's in comparison with some of the more detailed planning undertaken more recently (see Appendix Table 2.1-8). On the other hand, latest plans do envisage some railroad electrification in the South which would add a small load not included in the S&W load forecast (see Appendix Table 2.1-9).

Though the evidence available at present suggests that Karachi and the South will continue to increase their share of the total provincial industrial load, it will be necessary to keep the likely regional distribution of loads as well as their overall magnitude under close surveillance. As pointed out earlier, the regional pattern of load growth has important implications for some expensive investments in transmission. There are forces at work which could swing the balance of industrial load growth more in favor of the North—for instance, the growing shortage of water in the Karachi area and the possibility of significant industrial development around Kalabagh and Daudkhel. So it would be unwise to be too categorical on this matter.

APPENDIX TABLE 2.1-1
THE STONE & WEBSTER INDUSTRIAL LOAD FORECAST[a]
(mill. kwh)

	Estimated Actuals					Forecasts					Average Annual Rate of Growth 1965–85
	1960	1961	1962	1963	1964	1965	1970	1975	1980	1985	%
Northern Grid[b]	427	480	565	617	682	820	1,410	2,270	3,480	5,030	9.5
Upper Sind	—	1	1	1	1	10	145[c]	220[d]	300	409	20.0
Lower Sind	14	20	32	47	65	83	204	420	720	1,130	14.0
Karachi	110	127	161	217	286	355	850	1,750	2,950	4,440	13.5
Quetta	—	—	—	—	—	3	14	24	40	60	16.1
Other Utilities[e]	28	28	28	28	28	—	—	—	—	—	—
Self-Generation	520	530	535	535	537	544	650	915	1,000	1,103	3.6
Petrochemical Complex	—	—	—	—	—	—	130	480	920	1,390	—
Total	1,099 (8)	1,186 (12)	1,322 (9)	1,445 (11)	1,599 (14)	1,815 (13)	3,403 (12)	6,079 (9)	9,410 (8)	13,562	10.5

[a] Figures in parentheses are annual rates of growth in percentages.

[b] Excludes consumption at dam sites but includes an annual item of 30 million kwh which the power consultant estimated as the past and future supply of the Wah Ordnance Factory.

[c] Estimate assumes WAPDA would serve Esso fertilizer plant in 1970 with 100 million kwh at maximum load of 15 mw.

[d] Forecast based on power consultant's anticipation of substantial expansion in the fertilizer, cement, textiles and food processing industries.

[e] For the years 1960 through 1964, the regional distribution is given only for the estimated industrial sales of WAPDA and KESC; energy used for industrial purposes and generated by other utilities or by the industries themselves is listed separately. The figures for 1965 and subsequent years include all utility sales and a certain amount of energy demand that will accrue as firms give up generating their own power and transfer to the utilities.

APPENDIX TABLE 2.1-2

CONSUMPTION OF ELECTRICITY BY INDUSTRIAL SECTOR, 1962/63

Sector	Value Added (Factor Cost) Rs. mill.	Electricity Consumption (Millions of kwh) Purchased	Self-Generated	Total	kwh per Rs. 10 Value Added
Food					
Canning and Preserving	3.2	0.122	—	0.122	0.38
Grain Milling	36.9	8.753	—	8.753	2.36
Bakery Products	13.9	0.808	—	0.808	0.58
Sugar Mills	187.8	1.811	27.366	29.177	1.55
Edible Oils, etc.	56.2	23.244	7.789	31.033	5.52
Tea Processing	12.9	0.192	0.001	0.193	0.15
Salt	5.7	0.120	—	0.120	0.21
Total	316.6	35.050	35.156	70.206	2.22
Beverages					
Alcoholic Beverages	3.5	0.848	—	0.848	2.42
Nonalcoholic Beverages	21.4	1.935	—	1.935	0.90
Total	24.9	2.783	—	2.783	1.12
Tobacco	45.0	3.879	0.110	3.989	0.89
Textiles					
Cotton Textiles	404.1	169.706	127.136	296.842	7.35
Woolen Textiles	25.7	11.832	1.018	12.850	4.99
Silk, Art Silk	33.2	4.836	0.930	5.766	1.74
Dyeing and Printing	20.3	0.636	—	0.636	0.31
Knitting	14.4	0.156	—	0.156	0.11
Thread, Threadball	6.5	0.554	—	0.554	0.85
Textiles, n.e.s.	11.6	0.418	—	0.418	0.36
Total	515.8	188.138	129.084	317.222	6.15
Clothing, etc.					
Footwear	2.2	5.933	—	5.933	27.00
Wearing Apparel	5.3	0.046	—	0.046	0.09
Fabricated Textiles	7.2	0.090	—	0.090	0.13
Total	14.7	6.069	—	6.069	4.13
Furniture, etc.					
Wood, Cork Products	1.2	0.195	—	0.195	1.63
Wood Furniture	3.8	0.099	—	0.099	0.26
Metal Furniture	0.9	0.051	—	0.051	0.57
Total	5.9	0.345	—	0.345	0.58
Paper and Printing					
Board, Paper Products	22.9	7.331	—	7.331	3.20
Printing and Publishing	39.6	1.458	—	1.458	0.37
Total	62.5	8.789	—	8.789	1.40
Leather					
Tanning	50.1	0.795	—	0.795	0.16
Leather Products	2.0	0.028	—	0.028	0.14
Total	52.1	0.823	—	0.823	0.16

APPENDIX TABLE 2.1–2 Continued
CONSUMPTION OF ELECTRICITY BY INDUSTRIAL SECTOR, 1962/63

Section	Value Added (Factor Cost) Rs. mill.	Electricity Consumption (Millions of kwh) Purchased	Self-Generated	Total	kwh per Rs. 10 Value Added
Rubber					
Tires and Tubes	3.7	0.855	—	0.855	2.31
Other Rubber Products	4.5	0.410	—	0.410	0.91
Total	8.2	1.265	—	1.265	1.54
Chemicals					
Fertilizers	42.2	82.500	54.140	136.640	32.38
Paints and Varnishes	21.2	3.505	—	3.505	1.65
Perfumes, Soaps, etc.	8.4	0.271	7.720	70.991	9.50
Matches	0.2	0.142	—	0.142	7.10
Med. & Pharm. Chemicals	83.2	11.643	0.219	11.862	1.42
All Other Chemicals	80.5	3.679	5.330	9.009	1.12
Nonedible Vegetable Oils	5.9	2.956	1.278	4.234	7.17
Total	241.6	104.696	68.687	173.383	7.18
Oil Refining	53.2	3.357	8.393	11.750	2.20
Nonmetal Minerals					
Glass, Pottery Earthenware	9.6	1.860	0.573	2.433	2.53
Cement, Concrete Products	53.0	32.810	115.302	148.112	27.95
Nonmetal Minerals, n.e.s.	8.9	0.164	5.325	5.489	6.17
Total	71.5	34.834	121.200	156.034	21.84
Iron and Steel	58.0	12.965	0.706	13.671	2.36
Metal Goods	101.7	12.353	—	12.353	1.21
Machinery					
Agricultural Machinery	21.1	2.865	—	2.865	1.36
Engines, Turbines	14.2	1.232	—	1.232	0.87
Other Nonelectrical Mach.	70.6	43.762	18.259	62.021	8.78
Total	105.9	47.859	18.259	66.118	6.24
Electrical Goods	48.5	5.898	—	5.898	1.22
Transp. Equipment	108.4	8.392	21.850	30.242	2.79
Miscellaneous Manufacturing					
Surgical Instruments, etc.	8.1	0.391	—	0.391	0.48
Plastic Products	22.1	0.041	—	0.041	0.02
Sports Goods	2.5	0.091	—	0.091	0.36
Ice-Manufacture	1.8	3.359	0.620	3.979	22.11
Cotton-Ginning	117.3	3.849	1.623	5.472	0.47
Pens, Pencils, etc.	5.7	1.164	0.255	1.419	2.48
Total	157.5	8.895	2.498	11.393	0.72
Grand Total	1,992.0	486.390	405.943	892.333	4.48

APPENDIX TABLE 2.1–3
ESTIMATED INDUSTRIAL VALUE ADDED AND ELECTRICITY CONSUMPTION

	Value Added[a] (Rs. million)			Electricity Consumption (mill. kwh)	
	1962/63	1964/65	Index	1962/63	1964/65
Consumer Goods					
Sugar	187.8	135.0	72	29.177	21.007
Tobacco	45.0	62.0	138	3.989	5.505
Textiles (80%)	412.6	568.0	138	253.778	350.214
Board, Paper	22.9	27.0	134	7.331	9.824
Other Consumer Goods	501.6	616.0	123	91.236	112.220
Subtotal	1,169.9	1,408.0		385.511	498.770
Intermediate Goods					
Rubber	8.2	6.3	77	1.265	0.974
Fertilizers	42.2	28.7	68	136.640	92.915
Cement	53.0	55.5	105	148.112	155.517
Textiles (20%)	103.2	142.0	138	63.444	87.553
Cotton-Ginning	117.3	206.0	176	5.472	9.631
Chemicals and Refining	85.9	187.0	218	15.412	33.598
Other Intermediates	78.3	129.5	165	25.572	42.194
Subtotal	488.1	755.0		395.917	422.382
Investment Goods	334.0	507.0	152	110.905	168.576
Total Manufacturing	1,992.0	2,670.0		892.333	1,089.728
Power Consumption x 136[b]				1,210.0	1,480.0
Mining	110.5	134.0	121	20.0	24.0
Small Industry, etc.	1,020.0	1,071.0	105	200.0	210.0
Total Industrial Power Consumption				1,430.0	1,714.0

[a] Estimated on the basis of the national income accounts, data on the growth of physical production of certain important commodities given in the CSO Monthly Statistical Bulletin (mainly Central Board of Revenue figures), a paper by Wouter Tims, "Industrial Production in West Pakistan1959/60–1962/63" (May 27, 1966), IACA's estimates of the growth of agricultural production (for agricultural processing industries), and data on the index of manufacturing production provided by the Planning Commission. Estimates are in 1962/63 prices.

[b] 1964/65 power consumption by large-scale industry, "grossed up" in the same proportion as was necessary to gross up recorded industrial consumption in 1962/63 to cover the estimated total supply.

APPENDIX TABLE 2.1–4
PROJECTION OF CEMENT PRODUCTION[a]
(long ton thousands)

	1966	1967	1968	1969	1970	1975	1980	1985
Karachi	400	400	400	400	400	560	780	1,110
Hyderabad	540	1,140	1,140	1,140	1,140	1,490	2,100	2,940
Rohri	100	100	100	100	100	130	180	260
Daudkhel	250	250	250	250	250	250	250	250
Dandot	54	54	54	54	54	50	50	50
Wah-Hattar-Sangjani	560	560	680	800	800	1,120	1,560	2,200
Gharibwala	360	540	540	540	540	760	1,060	1,490
Kohat	180	180	180	180	180	250	350	500
Total	2,444	3,224	3,344	3,464	3,464	4,610	6,330	8,800

[a] Increases after 1970/71 are at an average rate of 7 percent per annum except in the case of the Daudkhel and Dandot plants, which are held constant.

APPENDIX TABLE 2.1–5

PROJECTION OF NITROGENOUS FERTILIZER PRODUCTION

(long tons of Nitrogen/thousands)

	1966	1967	1968	1969	1970	1971	1972	1976	1983
Existing Capacity and Planned Expansion									
Daudkhel: Ammonium Sulphate	10.5	10.5	10.5	19.0	19.0	19.0	19.0	19.0	19.0
(1 ton $(NH_4)_2SO_4$ = 0.21 ton N)									
Multan: Calcium Ammonium Nitrate	26.8	26.8	42.4	42.4	42.4	42.4	42.4	42.4	42.4
(1 ton $NH_4NO_3 + CaCO_3$ = 0.26 ton N)									
Urea	27.2	27.2	27.2	34.0	34.0	34.0	34.0	34.0	34.0
(1 ton $CO\ N_2H_4$ = 0.46 ton N)									
Planned New Capacity									
Mari-Esso: Urea	—	—	40.0	80.0	80.0	80.0	80.0	80.0	80.0
(1 ton $CO\ N_2H_4$ = 0.46 ton N)									
Daudkhel: Ammonium Sulphate Nitrate					78.0	156.0	156.0	156.0	156.0
(1 ton $(NH_4)_2\ SO_4 \cdot NH_4\ NO_3$ = 0.26 ton N)									
Kandkhot: Urea						115.0	230.0	230.0	230.0
Mari/Sui: Urea								230.0	460.0
	64.5	64.5	120.1	175.4	253.4	446.4	561.4	791.4	1,021.4

APPENDIX TABLE 2.1-6

PROJECTIONS OF ELECTRICAL ENERGY REQUIREMENTS OF MAJOR POWER-CONSUMING INDUSTRIES

(mill. kwh)

	1966	1967	1968	1969	1970	1971	1972	1975	1976	1980	1983	1984	1985
Northern Area													
Nitrogenous Fertilizer (Multan & Daudkhel)													
—Existing[a]	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
—Extensions[b]			20.2	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7
New Fertilizer Capacity (Daudkhel)					65.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Cement (Daudkhel, Dandot, Wah, Gharibwal, Kohat)[c]	210.6	237.6	255.6	273.6	273.6	290.6	308.6	369.6	392.6	499.3	598.1	635.0	674.5
Upper Sind													
Nitrogenous Fertilizer (Mari, Kandkhot)[d]	—	—	50.0	100.0	100.0	146.0	192.0	192.0	284.0	284.0	376.0	376.0	376.0
Cement (Rohri)[c]	15.0	15.0	15.0	15.0	15.0	15.0	16.0	21.0	22.5	27.6	33.8	36.1	38.7
Lower Sind													
Cement (Hyderabad)[c]	81.0	171.0	171.0	171.0	171.0	171.0	183.0	224.2	239.9	314.3	385.1	412.2	441.0
Karachi													
Cement[c]	60.0	60.0	60.0	60.0	60.0	64.2	68.7	84.2	90.1	118.0	144.6	154.7	165.5

[a] Taken as recorded for recent years.

[b] Power consumption rates used all include a 10% allowance for offices, cranes, packing facilities, workers' colony, etc.:

Ca. Amm. Nitrate: 340 kwh/ton of fertilizer or 1,300 kwh/ton of nutrient.
Amm. Sulphate: 100 kwh/ton of fertilizer or 500 kwh/ton of nutrient.
Urea: 630 kwh/ton of fertilizer or 1,500 kwh/ton of nutrient.
Amm. Sulph. Nitr.: 220 kwh/ton of fertilizer or 850 kwh/ton of nutrient.

[c] Power requirements for cement taken at the rate of 150 kwh per ton in order to make ample allowance for production of by-products, and for offices, workers' colony, conveyance systems, packaging, etc. This figure is in line with the Study Group's final estimate of the current consumption of electricity per ton of cement produced.

[d] The projected Esso plant at Mari is included at a consumption of 100 million kwh per year. This seems high but it is the figure given by the power consultant. The Kandkhot plant and subsequent large plants at Mari are assumed to use steam drivers making use of steam which is produced necessarily in the course of fertilizer-manufacture. Their energy consumption would thus be only about 400 kwh/ton N produced.

APPENDIX TABLE 2.1-7
"PLANNING COMMISSION" PROJECTION OF INDUSTRIAL GROWTH IN WEST PAKISTAN, 1965–85[a]
(Rs. million, 1959/60 prices)

	1965	1970	1975	1980	1985
Large-Scale Industry					
Capital Goods	348 (16.3)	741 (14.1)	1,433 (12.9)	2,628 (12.7)	4,777
Consumer Goods	1,236 (4.3)	1,528 (2.9)	1,759 (3.0)	2,039 (3.0)	2,363
Cement and Cement Products	83 (16.7)	176 (6.5)	241 (6.5)	330 (6.5)	452
Nitrogen Fertilizer	73 (30.0)	272 (25.0)	824 (7.4)	1,178 (5.4)	1,531
Other Intermediates	696 (6.7)	964 (8.4)	1,434 (10.0)	2,305 (7.0)	3,224
Subtotal	2,437 (8.6)	3,681 (9.3)	5,691 (8.3)	8,480 (7.8)	12,347
Mining	132 (9.9)	211 (8.4)	317 (8.4)	476 (7.6)	687
Small Industry, etc.	1,030 (2.6)	1,171 (2.6)	1,332 (2.6)	1,514 (2.6)	1,721
Total	3,599 (7.0)	5,063 (7.7)	7,340 (7.4)	10,470 (7.1)	14,755

[a] Figures in parentheses represent annual growth rates of the relevant sectors during the Plan periods in which they are inserted.

APPENDIX TABLE 2.1-8
POWER REQUIREMENTS OF PROPOSED PETROCHEMICAL COMPLEX AT KARACHI

	Production Capacity (tons/year)	Power Consumption (kwh/ton product)	Total Consumption (million kwh/year)
A. *Sanctioned Plants to be Commissioned by 1967–68*			
Plant			
1. Acetylene	5,800	2,350	13.65
2. Hydrocyanic Acid	4,000	1,000	4.00
3. Methylacrylate	700	240	0.17
4. Acrylonitrile	5,000	200	1.00
5. Polyacrylonitrile Fiber	5,000	2,000	10.00
6. Vinylchloride	5,500	113	0.62
7. Polyvinylchloride	5,000	420	2.10
8. Polyethylene	5,000	1,950	9.75
9. Polyester Fiber	3,500	3,767	13.20
10. B.H.C. (50% W.P.)	4,500	383	1.72
11. D.D.T. (50% W.P.)	2,500	3,000	7.50
12. Methanol	3,000	1,600	4.80
13. Formaldehyde	5,100	30	0.15
14. Ureaformaldehyde Resins	2,150	325	0.70
Total			69.36
Energy Requirement: 69.36 × 10^6 kwh			
Power Demand, at 90% load factor =	8,000 kw		
B. *Recommended Production Capacity to be Commissioned by 1969/70*			
1. Steam Cracking	160,000 light naphtha/year–65,000 tons ethylene at 70% P.F.	2,000	91.00
2. Acetylene	5,800	2,350	13.60
3. Hydrocyanic Acid	4,500	1,000	4.50
4. Butadiene	20,000	550	11.00
5. Carbon Black	6,000	500	3.00
6. Vinylchloride	11,000	113	1.24

APPENDIX TABLE 2.1–8 Continued

POWER REQUIREMENTS OF PROPOSED PETROCHEMICAL COMPLEX AT KARACHI

	Production Capacity (tons/year)	Power Consumption (kwh/ton product)	Total Consumption (million kwh/year)
7. Polyvinylchloride	10,000	420	4.20
8. Acrylonitrile	5,800	200	1.16
9. Methylacrylate	700	240	0.17
10. PACN Fiber	5,000	2,000	10.00
11. Methylmethacrylate	2,000	1,100	4.30
12. Polymethylenethacrylate	1,900		
13. Polyethylene	15,000	1,950	29.25
14. Ethanol	10,000	57	0.57
15. Ethylene Oxide	6,000	2,470	14.80
16. Ethylene Glycol	5,000	2,470	12.30
17. Styrene	15,000	212	3.18
18. Polystyrene	10,000	400	4.00
19. Polypropylene *Plant*	6,000	1,150	6.90
20. Isopropylalcohol	10,000	250	2.50
21. Glycerine	6,000	800	4.80
22. As-polybutadiene	8,000	555	4.44
23. Styrenebutadiene Rubber	17,000	700	11.90
24. Phthalic Oxlydride	5,000	1,000	5.00
25. Terephthalic Acid	4,500	800	3.60
26. Polyester Fiber	5,000	3,767	18.80
27. B.H.C. (50% W.P.)	4,500	383	1.53
28. D.D.T. (50% W.P.)	2,000	3,000	6.00
29. Alkali Electrolysis (Chlorine)	15,000	3,580	53.60
30. Methanol	20,000	1,600	32.00
31. Formaldehyde	20,000	30	0.60
32. Ureaformaldehyde Resins	5,000	325	1.62
Total			361.56

Energy Requirements: 361.56×10^6 kwh
Power Demand, at 90% load factor = 46 mw
All in Production in 1969–70.

C. *Recommended Production Capacity to be Commissioned by 1980*

1. Steam Cracking	250,000 light naphtha– 65,000 ethylene	2,000 for ethylene	131.00
2. Aromatic	68,500	350	23.97
3. Acetylene	12,000	2,350	28.20
4. Hydrocyanic Acid	8,000	1,000	8.00
5. Butadiene	30,000	550	16.50
6. Carbon Black	10,000	500	5.00
7. Vinylchloride	22,000	113	2.48
8. Polyvinylchloride	20,000	420	8.40
9. Acrylonitrile	12,000	200	2.40
10. Methylmeacrylate	1,500	240	0.36
11. Polyacrylonitrile Fiber	10,000	2,000	20.00
12. Methylmetacrylate	3,200	1,100	6.82
13. Polymethylmetacrylate	3,000		
14. Polyethylene	30,000	1,950	58.50
15. Ethanol	15,000	57	0.86
16. Ethylene Oxide	7,000	2,470	37.05
17. Ethylene Glycol	8,000		
18. Ethanolamines	2,000	330	0.66
19. Styrene	20,000	212	4.24

APPENDIX TABLE 2.1–8 Continued
POWER REQUIREMENTS OF PROPOSED PETROCHEMICAL COMPLEX AT KARACHI

	Production Capacity	Power Consumption	Total Consumption
	(tons/year)	(kwh/ton product)	(million kwh/year)
20. Polystyrene	12,000	400	4.80
21. Polypropylene	12,000	1,150	13.80
22. Isopropylalcohol	15,000	250	3.75
23. Glycerine	10,000	800	8.00
24. As-polybutadiene	10,000	555	5.55
25. Styrenebutadiene Rubber	25,000	700	17.50
26. Phthalic Anhydride	10,000	1,000	10.00
27. Terepthalic Acid	10,000	800	8.00
28. Polyester Fiber	10,000	3,767	37.67
29. Polyester Resins	10,000	100	1.00
30. Cydohexanol	22,000	1,660	36.52
31. Phenol	8,000	312	2.49
32. Caprolactain	10,000 }	1,660	31.54
33. Hydroxylamin Sulphate	9,000 }		
34. *Nylon-6 Fiber	10,000	11,700	117.00
35. B.H.C. (50% W.P.)	4,000	383	1.53
36. D.D.T. (50% W.P.)	2,000	3,000	6.00
37. Alkali Electrolysis (Chlorine)	15,000	3,580	53.70
38. Formaldehyde	35,000	30	1.05
39. Methanol	35,000	1,600	56.00
40. Phenol-Formaldehyde Resin	10,000	620	6.20
41. Urea-Formaldehyde Resin	10,000	325	3.25
42. Ethlether	1,000	125	0.12
43. Methylenechloride	1,000	1,400	1.40
44. Hexamethylenterramin	1,500	427	0.64
45. Pentacrythirtol	2,000	1,000	2.00
Total			783.95
		* Without Nylon Plant:	666.95

Total Energy Requirement, with Nylon Plant:	783.95×10^6 kwh
Average Demand, at 90% load factor:	100 mw
Total Energy Requirement, without Nylon Plant:	666.95 mill. kwh
Average Demand, at 90% load factor:	85 mw

Source: Karachi Electric Supply Corporation

APPENDIX TABLE 2.1–9
RAILWAY ELECTRIFICATION PLANS

From-To Stations	Distance	Peak Demand	Energy	Year of Commission
	(miles)	(mw)	($kwh \times 10^6$)	
Lahore to Khanewal	152 ST[a] 25 DT[b]	20	55	Dec. 1969
	Total	202 ST		
Lahore to Rawalpindi[c]	172 ST 7 DT	20	60	Fourth Plan
	Total	184 DT		
Karachi to Kotri[c]	115 DT	20	52	Fifth Plan
	Total	230 ST		
Sibi to Quetta[c]	64 ST	20	45	Sixth Plan

[a] Single Track. [b] Double Track. [c] Planning of these items is still under consideration.
Source: WAPDA and Railways Board.

The Residential Load

Stone & Webster's Forecast

The power consultant forecast that the residential load met by the power utilities in West Pakistan will increase at an average rate of about 12 percent per annum, from 380 million kwh in 1965 to 3,700 million kwh in 1985. The residential load as a proportion of total utility sales would increase slightly, from about 14 percent in 1965 to about 15 percent in 1985. The most significant growth, in absolute terms, would occur in the urban areas,[1] where the residential load would increase from 343 million kwh in 1965 to over 3,000 million kwh in 1985; but the rate of growth would be much higher in rural areas, where total residential load would increase from about 40 million kwh in 1965 to nearly 700 million kwh in 1985 (see Annex Table 2.2-1). Growth would be particularly rapid in the Sind, where the residential load is at present very small.

[1] "Urban" is defined by S&W as including those places which were cited by the 1961 Census as having a population in excess of 25,000 in 1961.

ANNEX TABLE 2.2–1
POWER CONSULTANT'S RESIDENTIAL LOAD FORECAST
(mill. kwh)

	1965	1970	1975	1980	1985	Implied Annual Growth %
North						
Urban	207.0	364.0	616	1,012	1,600	10.7
Rural	36.0	98.0	217	370	580	14.9
Upper Sind						
Urban	4.8	10.4	21	41	69	14.2
Rural	1.3	4.6	13	29	53	20.3
Lower Sind						
Urban	14.7	31.0	58	105	173	13.1
Rural	1.3	4.0	9	22	43	19.1
Baluchistan						
Urban	5.6	10.1	19	31	51	11.7
Rural	0.2	0.5	2	5	11	22.1
Karachi						
Urban	111.0	204	370	655	1,120	12.3
Total	382 (13.7)	727 (12.8)	1,325(11.4)	2,270(10.3)	3,700	12.0
Total Urban[a]	343	620	1,084	1,844	3,013	11.5
Total Rural[a]	39	107	241	426	687	14.6

[a] 25,000 population is the dividing line.

ANNEX TABLE 2.2–2
PROJECTION OF RESIDENTIAL ELECTRICITY CONNECTIONS[a]
(thousand)

	1965 Estimated Existing	1970	1975	1980	1985
North—Urban	290	407	571	786	1,071
—Rural	234	500	864	1,257	1,653
Sind —Urban	27	36	72	112	162
—Rural	16	43	86	164	264
Baluchistan	10	16	29	46	69
Karachi	89	135	200	287	400
Total	666	1,137	1,822	2,652	3,619
Average Yearly Increase	94	137	166	193	

[a] Calculated from the power consultant's load forecast on his assumption that the ratio between connected houses and connections (customers) is now and will remain about 1.4:1 outside Karachi and about 1.15:1 in Karachi.

Growth of the residential load would generally be more rapid in the early part of the 20-year period and would tail off towards the end (also see the more detailed summary of the S&W forecast in Annex Table 2.2-15). Average annual consumption per house would rise from an estimated 420 kwh in 1965 (about 600 in urban areas and 100 in rural areas) to about 750 kwh in 1985 (about 1,300 in urban areas and 250 in rural areas). The proportion of the total population electrified would rise from an estimated 10 percent at present (35 percent in urban areas and 5 percent in rural areas) to about 35 percent in 1985 (55 percent in urban areas and 25 percent in rural areas).

This large increase in the domestic supply of electricity will involve very substantial investments in distribution. S&W's estimate of the number of connections implied by their load forecast is given in Annex Table 2.2-2. Comparable figures on new connections are not available. However, some comparison can be made with the figures given in Annex Table 2.2-3, provided that the remarks in the footnotes are borne in mind. These figures indicate that WAPDA made about 70,000 to 80,000 new connections (in the "general" tariff classification—i.e. including commercial customers) a year on average over the five years at an annual rate of growth of some 16.5 percent. About 50,000 of these were probably residential

ANNEX TABLE 2.2–3
RECENT GROWTH OF RESIDENTIAL CONNECTIONS
(number/thousand)

	1960	1961	1962	1963	1964	1965
WAPDA[a]	295	339	414	486	564	637
KESC[b]	67	72	78	86	96	
Other Utilities[c]	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.

[a] WAPDA figures, which refer to fiscal years, include commercial connections, which are probably about 10 percent of the total.

[b] KESC figures, while covering only residential customers, are only estimates because many residential customers in Karachi have more than one meter.

[c] No figures are available on connections maintained by the other electric utilities—chiefly REPCO in Rawalpindi and MESCO in Multan—but the total in existence is probably not large, at most 10 percent of those maintained by WAPDA.

customers. KESC appears to have been making about 8,000 new residential connections a year. If these five years saw an average of 60,000 to 65,000 new residential connections over the whole of West Pakistan, as the figures suggest, then S&W's targets are ambitious; but they do not appear to be impossible to attain—in the fiscal year 1965/66, WAPDA apparently made about 80,000 new residential connections. A rate of electrification higher than S&W's projection might be technically difficult to reach.

The 1960 Housing Census was available for the consultant's use, as well as a number of socioeconomic surveys of the major cities of West Pakistan and of some rural areas in the North; so the housing unit was selected as the basic building block of S&W's residential load forecast. 1965 was chosen as the base year. At the time when the forecast was made, actual data on residential sales in 1965 were not available. However, the power consultant projected residential load by regions from the data available on preceding years' sales; the number of housing units in existence in 1965 were projected on the basis of the 1960 Housing Census and the 1961 Population Census; the percent electrical saturation of houses by areas was estimated on the basis of available socioeconomic surveys, own field checks, and cross checks with any other available information. From the base year of 1965, S&W proceeded in the same manner, projecting the number of houses in each area in the key years 1970, 1975, 1980 and 1985, on the basis of population projections for those years, and then estimating the proportion of houses which might be expected to be electrified by each key year. The gradual growth of electricity consumption per house was also forecast on the basis of the estimated use in 1965. Multiplication of the electrified houses in each area by the projected average annual consumption per house gave a figure for total domestic consumption for each area in each key year.

To check the consistency of S&W's estimates with other portions of the overall development program prepared by the Study Group and its consultants, the Study Group subjected the power consultant's residential load forecast to detailed examination, using material gathered by S&W and information provided by WAPDA, KESC and the Planning Commission.

Since S&W and the irrigation consultant had used different population projections for their work, and since the irrigation consultant's projection appeared to be based on rates of population growth which may turn out to be somewhat low in the early part of the Perspective Plan period, the Study Group used a slightly higher population projection as the basis for its testing of the residential load forecast—about 67 million people in 1975 and 89 million in 1985.

Base-Year Sales

The figures regarding residential power load presented must be treated with some skepticism. The main utilities in Pakistan do not specifically record sales to residential consumers, let alone residential consumers in urban areas as opposed to rural areas; it is not even possible to determine with any great degree of precision the number of residential consumers in any area. Data on the smaller electric utilities are extremely sparse. However, to obtain as realistic a base as possible for projection purposes, the Study Group assembled residential sales of electricity in calendar year 1964 on the basis of data gathered by S&W, WAPDA and KESC

ANNEX TABLE 2.2-4
ESTIMATED RESIDENTIAL AND COMMERCIAL SALES, 1964
(mill. kwh)

	Domestic			
	Urban	Rural	Commercial	Total
North —WAPDA	135.0	35.0	40	210.0
Other Utilities	21.0	1.0	12	34.0
Upper Sind—WAPDA	1.5	1.0	2	4.5
Other Utilities	4.0	0.5	—	4.5
Lower Sind—WAPDA	13.0	1.7	6	20.7
Baluchistan—WAPDA and Others	4.7	0.6	3	8.3
Karachi —KESC	89.0	—	62	151.0
Total	269	40	125	433

accounts, and information gathered by the Central Statistical Office on the smaller utilities. The results are summarized in Annex Table 2.2-4.

The most detailed information was found in the 1955/56 National Family Expenditure (NFE) Survey of Karachi and other urban areas in Pakistan. However, this information is somewhat out-of-date and the survey was rather narrow in coverage, being largely confined to employees. Income-distribution data that have been collected more recently in wider surveys suggest that the NFE Survey failed to cover about the top 10 percent of family incomes. Therefore, to get at the relationship between income distribution and electrification, the data in the old NFE surveys of the Punjab, Peshawar and the Sind regarding proportions of the population in different income groups were adjusted to bring them roughly into line with the new broader studies; but the figures on the degree of electrification at a given income level were left unchanged. Karachi has been the object of several surveys, in particular a large-scale sample survey carried out by the Central Statistical Office and the Pakistan Institute of Development Economics in 1959–61; this study was used in place of the NFE Survey. The results, which check out quite well with S&W's aggregate estimates of urban electrification, are presented in Annex Table

ANNEX TABLE 2.2-5
RELATIONSHIP BETWEEN URBAN INCOME DISTRIBUTION AND ELECTRIFICATION, 1960–64

	Northern Grid			Sind and Baluchistan			Karachi		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Fam. inc. group (Rs./mo.)	% of Pop. in each group	% of (2) connected	% of Pop. connected (2 × 3)	% of Pop. in each group	% of (5) connected	% of Pop. connected	% of Pop. in each group	% of (8) connected	% of Pop. connected (8 × 9)
Less than 100	40.0	15.2	6.1	54.1	9.7	5.2	29.2	7.5	2.2
100–200	39.0	40.8	15.9	32.7	22.6	7.6	38.6	16.4	6.3
200–400	11.0	70.1	7.7	9.0	26.3	2.4	22.0	41.7	9.2
Over 400	10.0	95.0	9.5	4.2	50.0	2.1	10.2	75.4	7.7
	100.0		39.2	100.0		17.3	100.0		25.4

2.2-5. The table indicates that the vast majority of families,[1] even in the relatively prosperous urban areas, have incomes of less than Rs. 200 per month—about 70 percent in Karachi, 80 percent in the North and nearly 90 percent in the Sind and Baluchistan. At given income levels, electrification tends to be highest in the older cities of the North, and lowest in the Sind; however, Karachi stands out for the relatively low levels of electrification attained for families in the lower income brackets. Also, despite the fact that there are more families in Karachi than in the North in the higher income groups, electrification is much less widespread because of the significantly lower levels of electrification applying to each income group. Urban electrification is highest in the North and lowest in the Sind. The predominance of relatively low-income consumers is noticeable in WAPDA's area, while in Karachi the majority of consumers have family incomes in excess of Rs. 200 a month.

One striking aspect of these numbers is the extent to which electrification reaches families in quite low income groups, especially in the North. There, 15 percent of families with incomes of less than Rs. 1,200 per annum receive domestic supplies of electricity. Some explanation of this fact is provided by Annex Table 2.2-6 about Lahore, based on the detailed socioeconomic survey carried out there by the University of the Punjab. The high overall levels of residential electrification

[1] The definition of a "family"—a group of persons with a common head—is, of course, slightly different from the definition of a "household"—a family or group of persons living together and eating from the same kitchen. In practice, the difference in average size between a family and a household in West Pakistan does not appear to be significant.

ANNEX TABLE 2.2-6
LAHORE: RESIDENTIAL ELECTRIFICATION

(1) Area	(2) Density: Population per Dwelling	(3) Wealth % of Households Income Above Rs. 100/Month	(4) Wealth and Density Indicator (2 + 3)	(5) Actual % of Dwellings Electrified
1–3	15.8	58.4	74.2	74.3
5	12.3	49.2	61.5	63.1
7–8	14.0	47.1	61.1	68.2
10–11	20.7	63.7	84.4	81.7
13–14	24.5	60.0	84.5	86.4
15	14.5	52.2	66.7	59.6
16	10.4	59.7	70.1	90.9
17	17.5	62.6	80.1	89.6
18–20	14.3	54.9	69.2	84.1
21–22	12.3	67.0	79.3	83.7
23	16.9	55.3	72.2	83.4
24	21.7	63.2	84.9	83.1
25–26	35.0	50.6	85.6	84.5
27	27.3	53.2	80.5	80.7
28	14.1	62.2	76.3	70.7
29	15.4	62.7	78.1	80.9
30	9.1	35.1	44.2	31.3
31	9.6	35.5	45.1	54.7
34	10.1	40.9	51.0	47.7
Total	13.1	56.8		72.6

ANNEX TABLE 2.2-7
HYDERABAD: RESIDENTIAL ELECTRIFICATION

(1) Area	(2) Density: Population per Dwelling	(3) Wealth % of Households Income Above Rs. 200/Month	(4) Wealth % of Households Income Above Rs. 100/Month	(5) Actual % of Dwellings Electrified
1-A	7.5	23.5	53.7	23.0
2-G	5.0	8.6	37.4	4.1
3-G	6.1	9.1	37.3	11.0
4	9.0	21.2	53.8	33.0
5-G	5.0	12.0	38.5	16.0
6	5.2	12.2	42.9	6.0
7	11.3	29.1	69.1	41.0
8	4.5	15.0	47.0	17.0
9	6.6	21.7	51.8	50.0
10	6.9	20.6	47.7	33.0
11	5.7	5.8	33.0	4.0
12	4.2	5.2	12.2	—
13	3.9	15.0	45.8	55.0
14	5.7	10.5	38.1	—
Total	6.1	15.1	44.8	17.2

in Lahore are not representative for the North as a whole. The table indicates that in almost every section of Lahore the percentage of people receiving domestic supplies exceeded the percentage with family income exceeding Rs. 100 per month. The foregoing table indicated that, in the North as a whole, 60 percent of the families had monthly incomes greater than Rs. 100 per month, whereas only about 40 percent of the total families were electrified. The Lahore Table shows that striking differences between these percentages can be accounted for by high density. In other words, poorer families are able to have electricity because they join up with other families and live several families to one house. This fact comes out most strikingly in Areas 25-26 (Anarkali) and Area 27 (Gowal Mandi).

As an indication of the combined effects of income levels and density, Column 4 in Annex Table 2.2-6 was compiled by adding together Columns 2 and 3. In general, Column 4 shows a close correlation with Column 5. The main outstanding differences can be explained by the very high proportion of families with outstandingly high income levels in some areas (e.g., Area 16 (Gulberg) and Area 17 (Model Town)), and by the exceptionally low proportion of such families in other areas (e.g. Area 15 (Dharampura) and Area 30 (Shahdara)). In only two areas do the combined effects of income levels and density seem inadequate to explain the high degree of electrification recorded—Areas 18-20 (Wahdat Colony) and Area 23 (Mozang). Wahdat Colony is mainly a Government housing estate whose inhabitants receive quarters there as part of their remuneration. It was built by the Government and each house was electrified.

With an estimate of total residential sales in 1964 and the proportion of people in urban areas electrified, the base-year balance sheet on residential sales by areas can be drawn up (see Annex Table 2.2-8). This balance sheet is based on families or households rather than houses, the unit used by S&W, because income distribution data are available on the former and not the latter.

Growth of Residential Electrification

Comparative international studies undertaken in the Bank some years ago suggest that there may be a minimum family income level, about $500 per annum, at which electrification becomes possible if none of the costs are subsidized. This is believed compatible with about $60 as the cost of electrification of a very simple house (including wiring, but excluding the cost of electricity-using appliances). At the current exchange rate, $500 annual family income would correspond to a monthly income of about Rs. 200. The estimates given in Annex Table 2.2-5 imply that in Pakistan residential electrification extends substantially below this income level, and, moreover, that the bulk of WAPDA's customers are receiving family incomes of less than Rs. 200 per month. This partly results from the very high density of low-income families, as suggested by Annex Table 2.2-6, and partly no doubt from the fact that industrial enterprises in Pakistan and the Government often provide housing for their employees. The average income of families receiving domestic supplies of electricity is almost certainly higher. The 1955/56

ANNEX TABLE 2.2-8

Estimated Residential Consumption of Electricity, 1964

	Population (1000's)	Percent Electrified	Average Size of Electrified Household[a]	Households Electrified	Average Annual Use per Household[b] (kwh)	Total Consumption (mill. kwh)
North —Urban	5,650	40	6.5	346,690	448	156
—Rural	32,920	6	6.0	329,200	110	36
Upper Sind—Urban	390	16	6.0	10,900	530	5.5
—Rural	3,250	2	5.5	11,800	125	1.5
Lower Sind—Urban	760	18	6.5	21,050	620	13
—Rural	3,000	2	5.0	12,000	140	1.7
Baluchistan—Urban	121	35	5.5	7,700	610	4.7
—Rural	1,390	1	5.0	2,780	215	0.6
Karachi —Urban	2,420	26	6.0	104,870	850	89
Total	49,901	10	—	847,490	363	308
Total Urban	9,341	33	—	491,710	545	268.2
Total Rural	40,560	5	—	355,780	112	39.8

[a] Average household size in West Pakistan is about 5.5 persons, and electrified households are shown by the sample surveys to be somewhat larger on average. For instance, the Karachi survey found the average size of all households to be 4.4 persons, whereas the average size of an electrified household was 5.2 persons.

[b] Average consumption per household appears to be lower in the North than elsewhere in the country; this may be related to the fact that a larger proportion of the population is electrified in the North. Average consumption per household may have been higher than indicated here in Karachi (as S&W suggests). A billing analysis undertaken in 1964 suggested that the average consumption per household may have been about 900 kwh per year. However, the 1955/56 Family Expenditure Survey, while admittedly biased towards the lower income groups, suggests that the average connected employee family was then paying for between 200 and 350 kwh a year. Prior to 1956 KESC kept records which distinguished between residential and commercial customers and the amounts of energy supplied to each group. These figures indicate that average consumption per customer over the period 1951 to 1955 was about 540 kwh per annum and that average consumption was growing at a rate of about 4 percent per annum. Projection of the figure of 540 kwh in 1953 at 4 percent for 11 years suggests that average consumption per customer in 1964 would have been about 850 kwh. This corresponds exactly to the estimated average annual consumption of about 250 "middle-class" households interviewed by Zafar and Associates in 1963/64. An average annual consumption of 850 kwh per customer would suggest an average annual consumption per household of about 700–800 kwh, since there is more than one consuming household on some meters.

ANNEX TABLE 2.2-9
MONTHLY AVERAGE FAMILY INCOMES AND EXPENDITURE ON ELECTRICITY

Location and Class	Average Income of Electrified Families (Rs./Month)	Expenditure on Electricity (Rs./Month)	Electricity Purchases as % of Income
Hyderabad—Industrial	111	0.8	0.7
Hyderabad—Comm. & Govt.	138	3.1	2.2
Lahore —Industrial	142	2.8	2.0
Lahore —Government	201	4.2	2.1
Lahore —Commercial	227	5.1	2.2
Lyallpur	110	0.06	0.05
Mardan	93	0.3	0.3
Multan	120	0.08	0.07
Peshawar —Industrial	143	6.0	4.2
Peshawar —Government	191	3.2	1.7
Peshawar —Commercial	209	3.8	1.8
Quetta	125	0.5	0.4
Rawalpindi	216	0.8	0.4
Sialkot	135	3.6	2.7
Sukkur	130	0.9	0.7

National Family Expenditure Survey provides data from which the figures in Annex Table 2.2-9 have been computed, indicating that electricity expenditure accounted for only a very small proportion of the total purchases of average electrified households.

Electricity consumption is such a small item in family expenditure that there was most likely some undercounting in this survey. As an overall average it would seem reasonable to suppose that expenditures on electricity may account for as much as 3 percent of the income of electrified families. In the US, expenditures on electricity vary from about 1 percent of income in the high-income bracket to a maximum of 3 percent among low-income families. Annex Table 2.2-8 indicated that residential electrification in West Pakistan was most widespread in the urban areas of the North and that annual family consumption of electricity was about 450 kwh on average. If this electricity supply were charged at current WAPDA rates, it would cost about Rs. 0.215 per kwh or a total of nearly Rs. 100. On the assumption that electricity purchases are about 3 percent of annual income, this would imply that the average income of an electrified family in the North is about Rs. 260 per month. This figure is consistent with other partial data available.

As a first indication of the potential for expansion of residential electrification, it seems reasonable to calculate the existing backlog of families who might be expected to pay for domestic electricity supply if it were available—i.e., the number of families with monthly incomes in excess of Rs. 200 per month who are not yet electrified. If we assume that families just reaching the threshold level for electrification of about Rs. 200 monthly income can afford to spend about 2-3 percent of annual income on domestic electricity supplies, then this would imply that they could purchase, at current WAPDA rates, some 230-360 kwh a year. The lower figure, 230 kwh, is about the minimum supply required for an urban dwelling—enough, for instance, to support an iron or a radio for a year plus one 50-watt bulb burning six hours a day throughout the year. Comparison between the number of people in the two highest income groups (Annex Table 2.2-10), and

ANNEX TABLE 2.2–10
DISTRIBUTION OF INCOME IN WEST PAKISTAN[a]

Family Income Group (Rs./Month)	Percent of Population in Each Income Group: Urban North	Urban Sind	Karachi	Rural West Pakistan[b]
Less than 100	40.0	54.1	29.2	36.1
100–200	39.0	32.7	38.6	47.0
200–400	11.0	9.0	22.0	14.1
More than 400	10.0	4.2	10.2	2.8

[a] Data from the Quarterly Surveys of Current Economic Conditions, undertaken in 1963/64, probably provide better data than that used here, which is based mainly on older surveys by the Central Statistical Office and universities in Pakistan. However, data from this survey were received too late and in a too aggregated form to be used here. In general terms, the results of the new survey seem to indicate significantly higher income levels—less families in the lowest group and more in the top two groups, especially the Rs. 200–400 monthly income group. The data from the new survey are summarized below in terms of percentages of the urban, rural and total population:

Monthly Family Income	Urban	Rural	Total West Pakistan
(Rs.)	(%)	(%)	(%)
Less than 100	15.7	28.5	25.7
100–200	41.7	43.3	42.8
200–400	29.6	23.4	25.1
More than 400	13.0	4.8	6.4

[b] Data from Central Statistical Office, National Sample Survey (Second Round) 1960. The First Round of the National Sample Survey (1959) suggests a generally similar distribution of rural incomes, but a larger proportion of people in the lowest income group (less than Rs. 100) than in the second lowest (Rs. 100–200).

the proportion of people in those income groups already receiving domestic supplies of electricity yields the following estimate of the "existing backlog" in terms of families:

Urban North	33,000
Urban Sind	18,000
Karachi	62,000
Rural areas[1]	830,000

The figure for Karachi is important because it represents a relatively high proportion of the total population of the city (about 15 percent). The figure for rural areas is, of course, high (about 12 percent of total rural families) because of low incomes there and, more importantly, because of the absence of electricity supplies in most rural areas.[2] If this "backlog" were to be filled, then residential electrification would have to rise from about 40 percent of households to 44 percent in the Urban North, from about 18 percent to 27 percent in the Urban Sind, from 26 percent to 41 percent in Karachi, and from 5 percent to about 17 percent in rural areas.

[1] Settlements with less than 25,000 inhabitants each.

[2] The National Sample Survey (First Round) 1959 reported that only 5 percent of villages in West Pakistan were within one mile of a radio and nearly 40 percent were more than 10 miles distant from a radio. WAPDA data indicate that, by the end of 1966, about 2,000 villages had been electrified. This represents 5 percent of the 40,000 estimated total number of villages in West Pakistan.

ANNEX TABLE 2.2-11
"PERSPECTIVE PLAN" LEVEL OF RESIDENTIAL ELECTRIFICATION, 1985

	Urban North	Urban Sind	Karachi	Rural W. Pakistan
1. Population (millions)	16.7	4.0	6.2	62.1
2. Percent With Family Income Above Rs. 200/Month[a]	60.0	45.0	70.0	60.0
3. Population With Family Income Above Rs. 200/Month (mill.) (Line 1 × Line 2)	10.0	1.8	4.3	37.3
4. Average Size of Family	6.5	6.3	6.0	6.0
5. Electrified Families (mill.)	1.54	0.29	0.72	6.22
6. Stone & Webster's Projection[b]	1.49	0.26	0.57	2.69

[a] Calculated from Annex Table 2.2-10, by transferring all those presently in the Rs. 100-200 monthly family income group into the above Rs. 200 group.

[b] For comparability with our figures, the S&W estimates have been converted from a house to a family base, using the above projections of population and average size of family and S&W residential electrification percentages.

While these figures give some indication of the potential for further electrification within the existing income pattern, they show nothing about the long-term potential for residential electrification. The Perspective Plan, however, projects an approximate doubling of family incomes between the base of 1960-65 and the target date of 1985; the implications in terms of new residential connections should be meaningful if the same threshold level of Rs. 2,400 annual family income is maintained. The calculation is summarized in Annex Table 2.2-11. For purposes of comparison the S&W projections of electrified families, by areas, is included in the table as Line 6. It should be recalled that Line 5 understates to a residential electrification implied in the Perspective Plan because it completely excludes residential electrification below the Rs. 200 per month family income level; yet there is already a certain amount of electrification beneath this level. Most of the families below this income level who are presently connected will probably rise above the Rs. 200 threshold within the Perspective Plan period. Moreover, the figures shown above would still leave some room for electrification below the Rs. 200 income level to the extent that 100 percent electrification above that income level is not achieved.

The similarity between these "Perspective Plan" projections of residential electrification and the S&W projections is striking in urban areas. The greatest divergence occurs in the case of Karachi, where there is a higher proportion of the population concentrated in the higher income levels than elsewhere in Pakistan. The figures, based on estimated current income distribution, imply that by 1985 only 30 percent of the population would remain below the Rs. 2,400 per annum family income level in Karachi, as compared with 40 percent in the rest of West Pakistan.

RURAL ELECTRIFICATION

The figure of connected rural families derived from the Perspective Plan is very much higher than the S&W projection of rural electrification. The consultant estimates that 26 percent of the rural population might be connected by 1985, whereas the Study Group's figures suggest that 60 percent of the rural population will be above the threshold income level and hence will be connected. The assumption of a direct correlation between income level and electrification is much less realistic for rural areas, where the cost of electrification is higher than in town and where electric power is frequently simply not available close by. The extension of electrification to rural areas should be more closely related to the expansion of the tubewell program than to rural income levels, as it has been in recent years.[1]

Volume Two of this report recommends a very substantial program of tubewell development over the coming 20 years. By 1985, about 80 percent of the canal-commanded area in the Province would have been brought under the tubewell program, either for purposes of irrigation or for drainage of saline groundwater. Rough estimates suggest that about 30 percent of the rural population (as here defined) would be in areas covered by the tubewell program by 1975, and about 60 percent of the rural population would be in such areas by 1985. If the tubewell program is implemented, therefore, 60 percent of the rural population should by 1985 be living in areas where distribution lines have been constructed. Application of the threshold income concept to this proportion of the rural population would imply that about 3.7 million rural families (60 percent of 6.22) should be connected by 1985. This is about 1 million more than S&W's projection of rural families connected by 1985.

Even the lower S&W target of new rural connections—about 2.3 million over the 20-year period—implies a very sizable investment in rural electrification. The Third Plan allocates Rs. 255 million for electrifying 4,000 villages, or an average of Rs. 64,000 ($13,400) per village. This figure appears to be on the low side, but if it is accepted for present purposes, and if it is further assumed, following WAPDA documents, that an average of about 40 families would be connected in each village, then the cost of electrification works out at an average of about $335 per family. The consultant's target of rural electrification would imply an investment over the Perspective Plan period of about Rs. 3.7 billion or $800 million. It should be recalled that rural population has been defined here to include all those living in places of less than 25,000 inhabitants, so that many of the new connections may in fact be in small towns where, due to economies of scale in expanding the distribution system, the average cost might be less than $335 per family. Nevertheless it is clear that the cost will be high. The rural electrification target derived from the simple calculation on the basis of income distribution would imply an investment in rural residential electrification more than two-and-a-half times as great and even the target based on the tubewell program would imply an investment about 40 percent greater. The investment for the S&W program already seems an ambitious target; the increase in annual number of new connections required to implement the S&W program would place a heavy administrative burden on WAPDA.

The extent to which the S&W target of rural electrification would already represent a deviation from past experience is suggested by Annex Table 2.2-12 below. West Pakistan presently has a per capita income of about $95 at the current exchange rate, and the Perspective Plan would therefore imply a per capita income of a little less than $200 by 1985. The highest level of rural electrification pres-

[1] Most of the rural electrification which has taken place in recent years appears to have been in the SCARP I area.

ANNEX TABLE 2.2-12
COMPARATIVE LEVELS OF RESIDENTIAL ELECTRIFICATION[a]

Country	Year	Per Capita Income (US$)	Percent of Dwellings Electrified		
			Total	Urban	Rural
Australia	1961	1,254	96.2	99.2	81.3
Puerto Rico	1960	658	79.9	94.3	66.7
Cyprus	1960	446	43.1	90.4	21.5
Greece	1961	370	53.1	81.4	13.6
Malta	1957	334	72.9	84.1	60.5
Costa Rica	1963	329	54.6	93.5	31.6
Cuba	1953	313	55.6	82.9	8.7
Nicaragua	1963	296	40.8	76.0	4.5
Portugal	1960	237	40.5	88.5	27.4
Colombia	1951	214	25.5	63.5	4.2
Jordan	1961	205	17.0	39.2	1.4
Honduras	1961	182	14.6	56.7	1.9
Peru	1961	171	30.1	52.9	4.8
Syria	1962	159	38.0	87.7	10.5
UAR	1960	156	37.8	—	—
Iraq	1956	150	17.1	—	—
Ecuador	1962	148	33.1	79.5	9.2
Dominican Republic	1955	146	15.5	51.1	2.4

[a] Source: Derived from data given in U.N. Statistical Yearbook 1964. Incomes were converted into US dollars at official exchange rates or, in cases where free rates were given, at averages between official rates and free rates for the relevant years.

ently attained by countries in this range of incomes appears to be about 10 percent.

The income distribution and residential electrification patterns inferred above from the Perspective Plan might be criticized on the ground that they give insufficient place to the income-equalization target of the Plan. According to the projections used by the Bank, nearly 40 percent of the population would remain in 1985 with family incomes below Rs. 200 per month. These projections do of course still allow much room for equalization of incomes in the middle and upper ranges—with, say, a reduction in the heavy concentration of income among a small number of high income receivers and its redistribution among the middle groups. Moreover, these projections do imply much wider distribution of the benefits of economic growth than attained in other countries, insofar as rural electrification is carried much further than in countries already at Pakistan's projected 1985 income level. This is reasonable in view of the relatively low marginal cost of rural residential electrification that accompanies the tubewell program; as S&W point out, the tubewell program provides West Pakistan an unusual opportunity for spreading the benefits of electrification.

FUTURE LEVELS OF ELECTRICITY CONSUMPTION

The other main dimension of growth in residential power load, after increase in the number of connections, is growth of the average load per residential consumer. However, as previously pointed out, the utilities do not keep separate statistics on residential consumers. Such information as is available suggests that total residential load may have been growing in Karachi in the last few years at about 14 percent per annum, made up from 9 percent for connections and 5 percent for average consumption per household. WAPDA's residential load may have been growing at about 19 percent per annum, made up from 15 percent for connections and 4 percent for average consumption. Thus growth in the average consumption per household has been less important than increase in the number of consumers in both markets, but it has been more important as a component of overall residential load growth in Karachi than in the WAPDA area. This is in line with the data that indicate residential electrification is more highly concentrated in the upper income groups in Karachi than it is in the WAPDA area. It is also consistent with the results that might be expected from the different residential rate policies of KESC and WAPDA: a new customer in Karachi must make a substantial initial capital contribution, averaging Rs. 250 per domestic customer, to cover all connection costs over 100 feet from the nearest line, whereas a new WAPDA customer has no initial capital contribution to make but has to pay a higher rate for his electricity, which S&W estimates at about 21.5 paisa (US cents 4.5) per kwh.

Average annual consumption per electrified household was estimated above (Annex Table 2.2-8) at about 450 kwh in the Urban North, where electrification is most widespread, at 850 kwh in Karachi with its relatively high-income consumers, and about 600 kwh in the Sind where urban electrification is least widespread. The bulk of rural consumers are in the North and average consumption there is estimated at about 110 kwh per annum; average rural consumption again appears to be somewhat higher in the South where it is less widespread and the consumers, such as they are, are longer established. Comparative international research undertaken some years ago in the Bank suggested that electricity consumption by established residential consumers could grow in low-income countries at about 7 percent per annum. This would imply, for instance, that average con-

ANNEX TABLE 2.2-13

COST AND POWER CONSUMPTION OF SELECTED ELECTRICAL APPLIANCES

Appliance	Approx. Retail Price (Rs.)	Watts	Average Annual Use (hrs.)	Average Annual Electricity Consumption (kwh)
Domestic				
Fan (ceiling)	200	60	2,000	120
Fan (table)	150	55	2,000	110
Electric Heater (2 bars)	60	2,000	250	500
Electric Heater (1 bar)	40	1,000	250	250
Electric Iron	55	750	100	75
Electric Kettle	95	1,500	300	450
Water Heater (6-gallon)	550	1,000	200	200
Water Heater (12-gallon)	725	1,500	200	300
Sewing Machine	1,600	80	100	8
Hot Plate	150	1,000	350	350
Imported				
Electric Heater (2 bars)—UK	165	2,000	250	500
Electric Heater (1 bar) —UK	135	1,000	250	250
Air-Conditioner (2-ton)—US	4,700	2,080	2,000	4,160
Electric Iron —UK	95	750	100	75
Electric Kettle —Germany	125	650	300	195
Vacuum Cleaner —Japan	925	350	100	35
Refrigerator (5 cu. ft.) —Germany	1,600	95	7,000	665
Refrigerator (10 cu. ft.)	2,750	130	7,000	910
Washing Machine	3,800	480	100	48

sumption of existing consumers in the Northern towns would rise to about 630 kwh in 1970, 890 kwh in 1975, 1,240 kwh in 1980, and 1,740 kwh in 1985. An indication of how this demand might be built up is given in Annex Table 2.2-13, listing electrical appliances that a recent survey showed to be in use at present in some homes in Karachi. Opposite each appliance is placed an estimate of its initial cost and its annual energy requirement.

Many of these goods—including refrigerators, space-heaters, fans, radios and air-conditioners—are already produced in West Pakistan. Plans exist to produce most of the rest of them and some other appliances, such as vacuum cleaners and blenders, domestically by the end of the Third Plan. Nevertheless, in the past, a large number, apart from fans and radios, have been imported. Tariffs on such goods are high and, because these goods are scarce, the importers' mark-ups are also high. Prices of the same goods produced by the heavily protected domestic industry are also likely to be high. A reasonable assumption would seem to be that a family might have to pay some Rs. 1,300[1] to obtain enough appliances to raise average electricity consumption from the estimated current 450 kwh per annum to about 1,740 kwh per annum. For example, this might include the following:

	Kwh	*Rs.*
Electric Heater	250	40
Water Heater	300	725
Electric Kettle	450	95
Two Ceiling Fans	240	400
Iron	75	55
	1,315	1,315

The average income of a connected household in the Northern towns was estimated earlier at about Rs. 3,000 per annum (Rs. 250 per month). Can such a family, which should have by 1985 about Rs. 6,000 per year, be expected to purchase over 20 years a minimum of Rs. 1,300 worth of electrical equipment? An average annual expenditure of Rs. 65 on electrical appliances may not appear unrealistic by comparison with the family budget data collected by the 1955/56 NFE Survey; but the survey also suggested that among families surveyed with over Rs. 200 per month in income, even those with higher incomes still had to spend all but a tiny proportion of their incomes on food, clothing and housing.[2] However, this survey was somewhat biased toward lower income groups. Total average expenditure of Rs. 1,300 on electrical appliances over 20 years would represent a little less than 5 percent of the additional income that should accrue to the average electricity-consuming family over the 20-year period. Thus an average growth rate of 7 percent in electricity consumption by existing residential consumers seems reasonable when account is also taken of the likely gradual decline in both the price of

[1] Covering the cost of initial purchase only. Replacement costs are not taken into account here.
[2] Data from the Quarterly Surveys undertaken by the Central Statistical Office in 1963/64 confirm this fact. Average expenditure on furniture and utensils is shown at less than 1 percent of total consumption expenditure. One percent of the total expenditure over the next 20 years of the average electricity-consuming family, defined above, would clearly be less than Rs. 1,300. However, this does not give a clear guide for many reasons, e.g., electrical appliances are frequently built into a house and thus occur in expenditure surveys as part of rent.

electricity and the cost of electrical appliances, as economies of scale are achieved, and the likely high marginal elasticity of demand for consumer durables.

A factor of more significance in the overall residential load forecast, because of the important role that new connections will continue to play, is the average consumption level at which new consumers will come on line—and the rate at which their consumption will grow. Studies at the Bank have suggested that average consumption depends partly on income level and partly on the length of time that a family has had electricity (and has therefore been able to accumulate appliances). Most of the new consumers in West Pakistan will be in low-income groups (except perhaps for a few years in Karachi where there is a relatively sizeable number of families above the threshold level but still unelectrified). This will tend to keep their initial level of consumption low and to prolong the time required to accumulate appliances. The initial consumption level in the WAPDA area is probably around the minimum simply to provide lighting and a fan or a radio—about 250 kwh per annum. The shift of Government and related activities from Karachi to Lahore-Rawalpindi-Islamabad could have a noticeable effect on this initial level of consumption in the next few years. Moreover, over time, as income levels rise, appliances become more available at lower prices, and electricity itself becomes cheaper, initial consumption levels are likely to rise. In Karachi, initial consumption levels are probably above those experienced by WAPDA. With the significant backlog of unconnected families with sufficient wealth to be electricity consumers, this will probably continue to be the case for the next few years. The effect of the shift of Government to the North will probably be noticeable chiefly in cutting down the rate of growth of consumption by existing consumers in Karachi. In later years, when KESC's initial capital contribution requirement has been removed and KESC rates brought more into line with WAPDA's, there will likely be a rapid expansion of the number of consumers, and, since they will tend to be more in the lower income groups, their initial consumption level will be lower than suggested by past experience in Karachi.

The rate of growth of electricity usage of new consumers will probably be quite high in the early years after initial connection, especially where a backlog of families who could afford electricity relatively easily is being made up; it could well double within little more than five years. This would represent the extension of lighting, addition of a fan or two, a radio and an iron—all quite inexpensive items and cheap relative to their consumption of electricity. Over a slightly longer period the growth of consumption would probably slow down considerably, but it could remain above that experienced by older consumers for another few years.

Conclusions

To summarize the discussion in the preceding pages, the amount of electricity consumed in the household sector depends on the number of consumers, the rate at which their number is increasing, and the levels of consumption of both old and new consumers and the rate at which these increase. These various factors can be built into a formula and thus brought to bear in the forecast of residential power loads. The formula has been applied to each of the four main groupings of population used in this Annex—Karachi, Northern Urban, Sind and Baluchistan Urban, and West Pakistan Rural. The details are presented in Appendix 2.2-1.

ANNEX TABLE 2.2-14
STUDY GROUP'S CALCULATED RESIDENTIAL LOAD PROJECTION[a]
(mill. kwh)

	1964	1970	1975	1980	1985	Implied Annual Rate of Growth 1964–85 (%)
Urban						
North	156	320	570	933	1,476	11.3
Sind and Baluchistan	23	43	61	110	200	10.8
Karachi	89	187	338	570	872	11.5
Subtotal	268	550	969	1,613	2,548	11.3
Rural						
West Pakistan	40	78	159	304	546	13.3
Total	308 (12.6)	628 (12.4)	1,128 (11.2)	1,917 (10.0)	3,094	11.6
Stone & Webster Projection		727	1,325	2,270	3,700	

[a] Figures in parentheses represent average annual growth rates in percentage over the five-year periods in which they are inserted.

The results of this procedure are summarized in Annex Table 2.2-14 below. The proportion of population here assumed to be electrified is not substantially different in any year from the proportion projected by S&W. It is somewhat higher in Karachi, as indicated in Annex Table 2.2-11. For the rural areas the percentage electrification levels projected by S&W have been adopted, rather than the levels coming out of the income-distribution approach, for reasons given. The total number of families connected by 1985 is about 5.1 million, slightly higher than S&W's 4.9 million. Nevertheless, total sales to the residential sector come out consistently lower on this projection than on S&W's.

More than half of the overall difference between the two forecasts of residential load results from the fact that the calculated projection is based on an actual (1964) figure, whereas S&W used a projected (1965) basis; this is indicated by the fact that the overall growth rates in residential load implied in the two forecasts are very similar. If the Study Group's calculated growth rate is applied to S&W's base, then it would reach a residential load only about 250 million kwh or 7 percent lower than the S&W load forecast for 1985. The remaining difference between the two load forecasts results from the less rapid growth in average consumption per household that results from the assumptions used in the calculation made here. The figures used in the formula recognize that most of the newly connected households, except possibly in Karachi, will be ones which can barely afford electricity. Because of the relatively expensive nature of electrical appliances, such households will come on line with a rather low level of consumption. The number of kilowatt-hours consumed may then grow quite rapidly—at around 10 percent on average—as appliances are gradually accumulated, but, in the context of continuing large additions of low-income families to the total power system, this is inadequate to raise the overall average consumption per household very rapidly.

A detailed account of S&W's residential load forecast is given in Annex Table 2.2-15.

ANNEX TABLE 2.2–15
STONE & WEBSTER RESIDENTIAL LOAD FORECAST

	Population (000's)	% of Pop. Con- nected	Persons per House	No. of Connected Houses	Average Annual Use per House (kwh)	Total Energy (mill. kwh)	Rate of Growth Over Preceding 5 Years
1965							
North —Urban	5,950	41	6.0	406,000	510	207.0	—
—Rural	34,000	5	5.2	328,000	110	36.0	—
Upper Sind—Urban	411	19	5.6	14,000	340	4.8	—
—Rural	3,352	2	5.8	12,000	110	1.3	—
Lower Sind—Urban	679	25	7.0	24,000	613	14.7	—
—Rural	2,715	2	5.0	11,000	120	1.3	—
Baluchistan—Urban	370	15	4.2	13,000	430	5.6	—
—Rural	1,173	0.4	4.7	1,000	150	0.2	—
Karachi —Urban	2,550	26	6.6	102,000	1,090	111.0	—
Total	51,200	9.5	5.3	911,000	418	382.0	—
Total—Urban	9,960	34	5.9	599,000	613	343.0	—
Total—Rural	41,240	5	5.2	352,000	110	39.0	—
1970							
North —Urban	7,780	46	6.3	570,000	638	364.0	11.9
—Rural	37,750	10	5.4	700,000	140	98.0	22.3
Upper Sind—Urban	540	25	5.7	23,000	450	10.4	16.7
—Rural	3,726	5	5.8	32,000	145	4.6	28.7
Lower Sind—Urban	890	31	7.2	38,000	764	31.0	16.0
—Rural	3,014	4.6	5.1	28,000	150	4.0	25.2
Baluchistan—Urban	480	19	4.3	21,000	480	10.1	12.5
—Rural	1,260	0.7	4.7	2,000	190	0.5	20.5
Karachi —Urban	3,260	33	7.0	155,000	1,320	204.0	12.9
Total	58,700	14.9	5.6	1,569,000	463	727.0	13.7
Total—Urban	12,950	39.0	6.4	807,000	768	620.0	12.6
Total—Rural	45,750	9.0	5.4	762,000	140	107.0	22.4
1975							
North —Urban	10,220	50	6.4	800,000	770	616.0	11.1
—Rural	41,670	16	5.5	1,210,000	180	217.0	17.2
Upper Sind—Urban	712	31	5.8	38,000	550	21.0	15.1
—Rural	4,113	10	5.9	70,000	185	13.0	23.1
Lower Sind—Urban	1,174	38	7.2	63,000	920	58.0	13.3
—Rural	3,327	8	5.3	50,000	190	9.0	17.6
Baluchistan—Urban	614	22	4.4	31,000	612	19.0	13.5
—Rural	1,390	3	4.8	9,000	222	2.0	32.0
Karachi —Urban	4,080	39	7.1	230,000	1,610	370.0	12.6
Total	67,300	21.2	5.7	2,501,000	530	1,325.0	12.7
Total—Urban	16,800	44.5	6.4	1,162,000	933	1,084.0	11.8
Total—Rural	50,500	14.5	5.5	1,339,000	180	241.0	17.6
1980							
North —Urban	13,440	54	6.6	1,100,000	920	1,012	10.4
—Rural	45,645	22	5.7	1,760,000	210	370	11.3
Upper Sind—Urban	930	39	5.9	62,000	655	41	14.3
—Rural	4,510	17	5.9	129,000	225	29	17.4
Lower Sind—Urban	1,540	44	7.2	95,000	1,100	105	12.6
—Rural	3,640	15	5.4	100,000	220	22	19.6
Baluchistan—Urban	790	24	4.5	43,000	720	31	10.3
—Rural	1,505	7	4.8	22,000	225	5	20.1
Karachi —Urban	5,000	47	7.2	330,000	1,980	655	12.1
Total	77,000	28.0	5.9	3,641,000	623	2,270	11.4

ANNEX TABLE 2.2–15 Continued
STONE & WEBSTER RESIDENTIAL LOAD FORECAST

	Population (000's)	% of Pop. Con- nected	Persons per House	No. of Connected Houses	Average Annual Use per House (kwh)	Total Energy (mill. kwh)	Rate of Growth Over Preceding 5 Years
Total—Urban	21,700	49.8	6.6	1,630,000	1,131	1,844	11.1
Total—Rural	55,300	20.6	5.7	2,011,000	212	426	12.1
1985							
North —Urban	17,680	58.0	6.7	1,500,000	1,070	1,600	9.6
—Rural	49,690	27.0	5.8	2,314,000	250	580	9.4
Upper Sind—Urban	1,230	45.0	6.0	92,000	750	69	11.0
—Rural	4,910	25.0	6.0	205,000	260	53	12.8
Lower Sind—Urban	1,990	49.0	7.2	135,000	1,280	173	10.5
—Rural	3,960	23.0	5.5	165,000	260	43	14.3
Baluchistan—Urban	1,020	29.0	4.6	64,000	800	51	10.4
—Rural	1,640	10.0	5.1	33,000	330	11	17.1
Karachi —Urban	6,080	55.0	7.3	460,000	2,240	1,120	11.3
Total	88,200	34.0	6.0	4,968,000	744	3,700	10.2
Total—Urban	28,000	54.0	6.7	2,251,000	1,338	3,013	10.3
Total—Rural	60,200	26.0	5.8	2,717,000	253	687	10.0

APPENDIX 2.2-1

AN ILLUSTRATIVE FORECASTING TECHNIQUE

If it is assumed that the various types of growth affecting the residential load can be approximated by compound rates of growth that are held constant over five-year periods, then it is possible to summarize all the elements discussed in this Annex in a formula showing their aggregate effect on future residential consumption. The factors to be taken into account in the calculation are indicated as follows:

H_0 = initial number of households connected.
C_0 = initial average consumption per household.
c = rate of growth of consumption by original consumers.
r = rate of growth of households connected.
C'_0 = initial consumption of newly connected households.
c' = rate of growth of consumption by newly connected households within the five-year period in which they are connected and over the following five-year period.

Consumption at the end of a five-year period may be divided into consumption by old consumers and consumption by newly connected households. Consumption by old consumers will be

$$H_0C_0(1 + c)^5$$

while consumption by new consumers, taking each year's group together, will be

$$rH_0C'_0(1 + c')^4 + rH_0(1 + r)\,C'_0(1 + c')^3 + rH_0(1 + r)^2\,C'_0(1 + c')^2 + rH_0(1 + r)^3\,C'_0(1 + c')\,1 + rH_0(1 + r)^4\,C'_0$$

The sum of these two expressions, the total residential consumption in the fifth year,

$$H_5C_5 = H_0[C_0(1 + c)^5 + rC'_0[(1 + c')^4 + (1 + r)(1 + c')^3 + (1 + r)^2 (1 + c')^2 + (1 + r)^3(1 + c') + (1 + r)^4]]$$

but, $H_5 = H_0(1 + r)^5$ by definition, so that

$$C_5 = \frac{C_0(1+c)^5+rC'_0[(1+c')^4+(1+r)(1+c')^3+(1+r)^2+(1+r)^3(1+c')+(1+r)^4]}{(1 + r)^5}$$

$$= C_0\left(\frac{1 + c}{1 + r}\right)^5 + \left(\frac{r}{1 + r}\right)_5 C'_0[(1 + r)^4 + (1 + r)^3(1 + c')+(1+r)^2(1 + c')^2 + (1 + r)(1 + c')^3 + (1 + c')^4]$$

$$= C_0\left(\frac{1 + c}{1 + r}\right)^5 + \left(\frac{r}{1 + r}\right) C'_0 \left[1 + \left(\frac{1 + c'}{1 + r}\right) + \left(\frac{1 + c'}{1 + r}\right)^2_2 + \left(\frac{1 + c'}{1 + r}\right)^3 + \left(\frac{1 + c'}{1 + r}\right)^4_4\right]$$

This equation can be further simplified by replacing the series in the second term with a formula for the sum of the terms:

$$C_5 = C_0\left(\frac{1 + c}{1 + r}\right)^5 + \left(\frac{r}{1 + r}\right)C'_0\,\frac{1 - \left(\frac{1 + c'}{1 + r}\right)^5}{1 - \left(\frac{1 + c'}{1 + r}\right)}$$

This calculation has been made for each major market for each of the periods, 1964–70, 1971–75, 1976–80 and 1981–85, and is summarized in the Appendix Tables. In the use of the above equation, the number of consumers in each of the key years has been projected on the basis of the assumption regarding a threshold income level described in the Annex. The growth rates of consumption have also been selected on the basis of the considerations discussed there, with special attention to the income level of consumers and their initial levels of electricity consumption. Starting levels of consumption for new consumers have been estimated on the basis of existing average consumption levels, a detailed breakdown of KESC's sales (under Tariff R1) to residential consumers by amount of monthly consumption, and comparative international research in the Bank. An attempt has been made to take account of the shift of Government to the North in the assumptions fed into the analysis for the Northern cities. Equally allowance has been made in the Karachi analysis for the sizeable backlog of relatively high income families who are not yet electricity consumers; and the sizeable jump in the level of electrification in Karachi between 1970 and 1975 is postulated on the assumption that KESC's initial capital contribution requirement will be either reduced or eliminated.

APPENDIX TABLE 2.2-1
NORTHERN CITIES

	1964		1970		1975		1980		1985
Application of Formula									
Population Electrified (%)	40		45		49		54		60
Old Consumers									
Number (000's)	347		533		754		1,106		1,500
Average Consumption (kwh)	450		600		754		844		984
Growth of Consumption (% p.a.)		8		7.5		6.5		6.5	
New Consumers									
Growth of Connections (% p.a.)		7.2		7.5		8.0		6.3	
Initial Average Consumption (kwh)		300		350		400		450	
Initial Growth of Consumption (% p.a.)		11		10		9		9	
Total Residential Sales (mill. kwh)	156		320		570		933		1,476
Stone & Webster Forecast	1965		1970		1975		1980		1985
Houses Electrified (%)	41		46		50		54		58
No. of Houses Electrified (000's)	406		570		800		1,100		1,500
Use per House (kwh)	510		638		770		920		1,070
Total Residential Sales (mill. kwh)	207		364		616		1,012		1,600

APPENDIX TABLE 2.2–2

SIND AND BALUCHISTAN: URBAN AREAS

	1964	1970	1975	1980	1985
Application of Formula					
Population Electrified (%)	20	24	32	38	45
Old Consumers					
Number (000's)	40	67	117	181	280
Average Consumption	585	638	525	605	712
Growth of Consumption (% p.a.)		6	7	7	7.5
New Consumers					
Growth of Connections (% p.a.)		9	11.9	9.1	9.1
Initial Average Consumption (kwh)		275	300	300	350
Initial Growth of Consumption (% p.a.)		11	11	11	11
Total Residential Sales (mill. kwh)	23	43	61	110	200
Stone & Webster Forecast	1965	1970	1975	1980	1985
Houses Electrified (%)	20	25	31	36	41
No. of Houses Electrified (000's)	51	82	132	200	291
Use per House (kwh)	490	622	742	935	1,007
Total Residential Sales (mill. kwh)	25	51	98	187	293

APPENDIX TABLE 2.2–3

KARACHI

	1964	1970	1975	1980	1985
Application of Formula					
Population Electrified (%)	26	34	48	59	65
Old Consumers					
Number (000's)	105	181	319	502	673
Average Consumption (kwh)	850	1,032	1,062	1,136	1,296
Growth of Consumption (% p.a.)		8	8	7	7
New Consumers					
Growth of Connections (% p.a.)		9.5	12.0	9.5	6.0
Initial Average Consumption (kwh)		500	400	450	500
Initial Growth of Consumption (% p.a.)		9	10	10	9
Total Residential Sales (mill. kwh)	89	187	338	570	872
Stone & Webster Forecast	1965	1970	1975	1980	1985
Houses Electrified (%)	26	33	39	47	55
No. of Houses Electrified (000's)	102	155	230	330	460
Use per House (kwh)	1,090	1,320	1,610	1,980	2,240
Total Residential Sales (mill. kwh)	111	204	370	655	1,120

APPENDIX TABLE 2.2–4

RURAL WEST PAKISTAN

	1964	1970	1975	1980	1985
Application of Formula					
Population Electrified (%)	5	10	15	20	26
Old Consumers					
Number (000's)	356	761	1,268	1,900	2,690
Average Consumption (kwh)	112	102	125	160	203
Growth of Consumption (% p.a.)		7	7	8	8
New Consumers					
Growth of Connections (% p.a.)		13.5	10.7	8.5	7.2
Initial Average Consumption (kwh)		70	80	90	100
Initial Growth of Consumption (% p.a.)		12	12	12	12
Total Residential Sales (mill. kwh)	40	78	159	304	546
Stone & Webster Forecast	(1965)				
Houses Electrified (%)	5	9	14.5	20.6	26
No. of Houses Electrified (000's)	352	762	1,339	2,011	2,717
Use per House (kwh)	110	140	180	212	253
Total Residential Sales (mill. kwh)	39	107	241	427	687

SUPPLEMENTAL PAPER III

The Price of Thermal Fuel for Planning Purposes

INTRODUCTION

The chief known energy resource in West Pakistan is its hydroelectric potential. There are also important reserves of natural gas. Coal is found in a number of places but is of low quality. There are also some minor oil fields in the Province. This Paper briefly discusses these various domestic sources of energy and the costs of plant to produce electricity from them and the related price of thermal fuel for planning purposes.

Most of the electricity presently generated in West Pakistan comes from thermal plants fired by natural gas from the Sui field, on the one hand, and the hydroelectric plants in the North, on the other. According to estimates developed in the next section about 45 percent of the electric energy generated in West Pakistan in 1964 was produced from natural gas in plants belonging to the electric utilities, and 40 percent came from WAPDA's hydroelectric plants. Most of the remainder was produced from natural gas in privately owned generators and from imported fuel oil. Coal plays an extremely minor role in the generation of electricity. Details regarding existing generating equipment operated by WAPDA and KESC in the four main grid systems of West Pakistan have been presented in Volume One.

THE OVERALL ENERGY SITUATION—SUPPLY AND DEMAND

Hydroelectric Resources

West Pakistan's hydroelectric potential has been estimated at 10 million kw, but this figure is probably conservative. Less than 250,000 kw have been developed so far. Most of the power programs studied in this Report involve the development of about 1 million kw at Mangla and 2 million at Tarbela.

It is difficult to compare hydroelectric resources directly with mineral fuel resources because of the self-renewing nature of the former. But it is clear that the thermal value of the Province's hydroelectric resources, calculated in terms of the thermal fuel that would be required to generate an equivalent amount of electric power, is large. If we assume an average 60 percent capacity factor (allowing for seasonal fluctuations in river flows and in heads on the turbines) then the 10 million kw estimate of total hydro potential would be equivalent to about 52,000 million kwh or about 600 trillion Btu each year.[1] The hydroelectric projects in-

[1] Taking an average heat rate of 12,000 Btu per kwh sent out.

cluded in the recommended program, together with the existing hydro plant, would by 1985 produce about 20,000 million kwh per year, equivalent to about 240 trillion Btu's.

Mineral Fuel Resources

There is inevitably enormous uncertainty attaching to estimates of mineral fuel reserves, and the figures given below for different fuels cannot be taken as anything more than order-of-magnitude estimates, based on the most recent information available to the Study Group. The discussion in the following paragraphs is confined largely to mineral fields that are already known to exist as potential sources of energy. There is great uncertainty about the size and quality of these reserves. But there are probably other mineral-fuel reserves in West Pakistan which have not yet been discovered. Moreover technological development may make it possible to tap other potential sources of energy effectively. Research is presently underway in Pakistan, for instance, on the use of solar energy and of the energy of the wind for generation of electricity. However, the approach adopted here is to try to make a reasonable assessment of fuel reserves that may be considered reliable, at the present rate of known technology, for purposes of long-term planning.

Natural Gas Reserves

By far the most significant known mineral reserves in West Pakistan are the natural gas fields. Current estimates put recoverable reserves of gas in known fields at about 13 trillion cubic feet.[2] Some of the fields, however, have gas of very low quality, as can be seen in Table 3A-1, so that total reserves are equivalent to about 10,000 trillion Btu.

Since sizeable gas fields were first discovered in the early 1950's, two have been developed—one a relatively small wet field (i.e. gas found along with oil) in the north near Rawalpindi, at Dhulian, and the other a large dry field some 50 miles northwest of Gudu Barrage, at Sui. A 347-mile, 16-inch pipeline was laid from Sui to Karachi in 1955 and another 217-mile, 16-inch pipe from Sui to Multan in 1958. The Multan pipeline has recently been extended to Lyallpur, Lahore and Rawalpindi where it has been linked with the small Dhulian system which has been supplying gas locally since 1957. Out of the total gas sales of about 45 billion cubic feet in 1964 about 3 billion came from Dhulian and the remainder from Sui; two-thirds of the Sui gas went to the South (chiefly Karachi). Late in 1967 or early in 1968 a third gas field will come into production—the Mari field, located across the Indus River from Sui, some 40 miles southeast of the Gudu Barrage. Esso Standard (Eastern) is constructing a 175,000-ton urea plant close to the field at Dharki.

Besides Sui, Dhulian and Mari there are a number of other known gas fields in West Pakistan but, according to the engineers who have investigated them, they are either so small or their reserves of such low quality that they are not likely to be useful except for local use or for linking with the existing pipelines. There are two small fields—one about 30 miles south of Sui, at Khandkot, and the other much

[2] Trillion, as used in this Report, means million million (10^{12}). The following discussion uses the abbrevations Mcf, meaning 1,000 cubic feet, and MMcf, meaning 1,000,000 cubic feet.

TABLE 3A-1
WEST PAKISTAN NATURAL GAS RESERVES

Field	Net Recoverable Reserves of Raw Gas (trillion cu. ft.) Est. of Jan. 1960	Est. of Jan. 1965	Standard[a]	Main Chemical Components (%) Methane	Dioxide	Nitrogen	Gross Heating Value Btu/cu. ft.
Sui Quality Gas							
Sui	6.00	6.00[b]	5.60	88.5	7.4	2.5	933
Khandkot	0.20	0.20	0.17	79.2	2.5	16.6	842
Mazarani	0.03	0.03	0.03	87.0	0.3	8.0	976
Subtotal	6.23	6.23	5.80				
Other Important Fields							
Dhulian	1.70	1.70	1.87	81.5	0.5	—	1,100
Mari	3.50	1.8[c]	1.30	66.2	9.0	17.0–18.0	725
Sari[d]	—	0.3	0.21	n.a.	n.a.	n.a.	700
Subtotal	5.20	3.80	3.38				
Local Use Only							
Uch	2.50	2.50	0.77	27.3	46.2	25.2	308
Khairpur	0.25	0.25	0.03	12.2	70.6	16.9	130
Zin	0.10	0.10	0.05	46.1	44.7	8.5	484
Subtotal	2.85	2.85	0.85				
Grand Total	14.28	12.88	10.03				

[a] Reserves, as estimated in January 1965, converted into standard cubic feet of 1,000 Btu/cu. ft.

[b] An additional 0.3 trillion cu. ft. of reserves was discovered at Sui between 1960 and 1965, but consumption in the period was also about 0.3 trillion cu. ft.

[c] The Third Five Year Plan document gives an estimate of 5 trillion cubic feet for Mari. This appears to be total reserves without allowance for inerts and loss in recovery. Further investigations at Mari have moreover revealed that the field may be less extensive than was then believed and that the conate water saturation may be higher. Recoverable reserves, without risk factor adjustment, are currently estimated at 1.8 trillion cubic feet. (See text.)

[d] Sari Sing field, some 40 miles northeast of Karachi, is still under investigation and it is still unclear what the reserves may turn out to be. The figure used here is a reasonable guess at a given stage of knowledge.

smaller and more inaccessible at Mazarani in Larkana District—which are believed to have gas of sufficient quality that it might be fed into the long-distance transmission lines. Another gas field which has recently been discovered some 40 miles northeast of Karachi, at Sari Sing, appears to fall into this same category of reasonable quality but small reserves (probably between 0.1 and 0.4 trillion cubic feet). The remaining three fields listed on Table 3A-1 under the heading "Local Use Only" have gas which is of too low quality to warrant long-distance transmission. The largest is at Uch, about 30 miles west of Sui; its gas, being about 25 percent nitrogen and 50 percent carbon dioxide, has a heating value of only about 300 Btu/cubic foot. It has been suggested that it might eventually be useful for local production of fertilizers or petrochemicals. The gas in the neighboring Zin field is believed to have a slightly higher heating value but the field is much smaller and would also probably not find more than local usage. The

Khairpur gas field is quite extensive but has 70 percent carbon dioxide content which excludes all but local use. Consultants have suggested that it would probably best be reserved for the recovery of carbon dioxide which is used for refrigeration, carbonation and manufacture of a number of chemicals.

The Sari Sing field, though it is small, could come to play a very useful role because of its location close to the largest existing market for gas in West Pakistan. The figure given in Table 3A-1 for reserves at Sari Sing in terms of standard cubic feet (i.e. a cubic foot of 1,000 Btu thermal value) is about 10 times current annual gas consumption in the Karachi area. Sari could therefore supply the Karachi market for a few years. But, in view of the fact that the pipeline from Sui with peak day capacity of about 110 MMcf already exists, a more rational use would probably be to use Sari Sing for meeting peak demands and thereby postpone the need for expansion of the pipeline all the way from Sui. Once some of the native gas was removed from the Sari field, it might, moreover, prove feasible to develop the field as a storage reservoir. To be suitable for conversion to storage a gas field must have certain geological characteristics: sufficient permeability to permit high rates of gas injection and withdrawal, good porosity, an overlay of impermeable rock, and an anti-clinical or dome-like structure to permit easy evacuation of the gas from the field. It is not known whether the Sari Sing field has these characteristics, but if it does, then it would probably be appropriate to develop it for storage. This would probably mean that at least 50 percent of the field's own reserves of gas would have to remain in the field as cushion gas, but it would also mean that the Sui-Karachi line would only have to be expanded sufficiently to cope with average-day requirements. Storage potential at Sari would become a particularly valuable asset if the Karachi area was linked by EHV transmission with the hydroelectric plants in the North so that gas requirements for power generation in Karachi would likely become very fluctuating; this matter is discussed in greater detail in subsequent Papers in this Volume.

Since requirements of thermal fuel for power generation will fluctuate over time even more heavily in the North than in the South, as units are installed at Mangla and Tarbela, it would probably also be attractive to develop any cheap sites for gas storage that may be discovered there. An obvious possibility would be injection of gas at the Dhulian field; under normal circumstances gas injection in a wet field should have the additional advantage of raising the oil output from the field. However, Attock Oil Company has apparently investigated the possibily of gas storage at Dhulian and found it technically infeasible. Some consideration has been given to other possible sites for storage in the North, but none has yet been found. It is clear that the lack of cheap fuel storage facilities in the North will cause WAPDA's thermal fuel supplies to be relatively expensive; further search for cheap gas storage sites in the North would therefore be very worthwhile.

The thermal value of recoverable reserves in the different fields, as currently estimated, is shown in the third column of Table 3A-1 which converts reserves into standard cubic feet of 1,000 Btu/cubic foot thermal value. This column brings out the importance of the Sui field and shows the relative insignificance of the Uch, Khairpur and Zin fields. Dhulian is the second most important field after Zin in terms of total thermal values of reserves. However, the rate of off-take from Dhulian is limited by technical conditions to a maximum that is currently taken as about 12 MMcf/day. Mari appears to be the only other major field, but the validity of the reserve estimate is very uncertain; it could be considerably larger and it could be smaller than currently estimated. As the Table indicates, the Second Plan document (1960) used an estimate of 3.5 trillion cubic feet and the Third Plan document raised this to 5.0 trillion cubic feet. At that time only three wells had been drilled, and of these only one definitely produced gas. Utilization became an immediate prospect at the end of the Second Plan period and in 1965/66, 6 more wells were drilled to test the field. One of these wells proved dry and this led to a reestimate of the real extent of the field. More importantly, the estimate of the conate water saturation which had before been put at 28 percent was increased, on the basis of a more detailed core analysis of samples from the new wells, to 44 percent. Proven recoverable reserves are now estimated by Esso at 0.64 trillion cubic feet; they represent the estimated content of the drainage basin of the two central wells investigated. Total recoverable hydrocarbons are estimated at 1.8 trillion cubic feet, and this is the figure used in the Table. A more conservative assessment would adjust this figure for greater uncertainties the further the gas is believed to be from the area which has been most fully explored; this would reduce this estimate to 1.2 trillion cubic feet.[1]

Apart from the nine structures listed in Table 3A-1, which are known and, at least to some degree tested, there are probably others in West Pakistan. It was estimated in 1959 by engineers who had been involved in exploration activities in the Province that West Pakistan might have additional recoverable natural gas reserves of about 5 trillion cubic feet in structures and traps that had not been tested. Exploratory activity in the interim has not been as intensive as it would have been had a shortage of gas been imminent. However, according to Planning Commission estimates, the Government invested about Rs. 177 million during the Second Plan period in prospecting for oil and gas in West Pakistan and private companies, both Pakistani and foreign, invested a further Rs. 120 million to the same end. Yet no new fields have been discovered since the above estimate of unknown reserves was made—with the possible exception of the small Sari Sing field which is still under investigation.

Coal Reserves

The second most important mineral reserve in West Pakistan from the energy point of view is coal. There are a number of fields, most of which have been known for some years and most of which are exploited to some degree; total provincial coal production has increased at a rate of about 10 percent per annum over the last 10 years to a 1964 level of about 1.2 million tons. The coal produced is of the semibituminous type, ranging between about 8,000 and 11,000 Btu per lb. It is friable and relatively high in sulphur and ash content, but is suitable for direct use in the firing of brick kilns and boilers and for use in the form of coke

[1] Total hydrocarbons in the Mari field are estimated at 3.3 trillion cubic feet. Deduction of inerts and irrecoverables brings the estimate to 1.8 trillion cubic feet. This is composed of three portions—Proven reserves, or those in the central portion of the field, Probable reserves, or those estimated on the basis of wells drilled away from the center of the drainage basin, and Possible reserves, or those estimated on the basis of wells drilled at what is believed to be the edge of the field. The figure of 1.2 trillion cubic feet is derived by giving Proven reserves a weight of 100 percent, Probable reserves a weight of 50 percent and Possible reserves a weight of 25 percent.

TABLE 3A-2
WEST PAKISTAN—COAL RESERVES

	Estimated Reserves	Thickness of Seams (ft)		Depth of Seams	Moisture	Volatile Matter	Fixed Carbon	Ash Content	Sulphur	Calorific Value	Btu's
	(mill. tons)	Max.	Av.	(ft)	(%)	(%)	(%)	(%)	(%)	(Btu/lb)	(trillion)
Baluchistan and Kalat											
Sor Range }					9–14	38–44	43–44	4–6	1–3	10,400–11,900	
	22										500
Deghari }					11–14	35–39	42–43	5–12	1–4	9,750–10,800	
Mach	15				7–12	34–39	32–42	10–20	3–7	9,200–10,300	300
Sharigh	40				2–4	35–45	26–44	9–35	5–7	8,500–12,400	900
Punjab-Trans-Indus											
Makerwal	19				3–5	42–48	37–45	6–12	3–6	11,400–12,200	500
Punjab-Cis-Indus											
Salt Range	70				3–8	26–39	30–45	12–38	4–11	7,100–11,100	1,300
Sind											
Jhimpir-Meting	28	9	1.5		15–30	30–40	31–36	8–15	3–7	7,400–9,800	500
Lakhra	130	8	4	<500	32–36	28–31	27–30	7–11	3–6	7,010–7,600	2,000
	324									Total	6,000

briquettes in foundries, lime kilns and sugar mills. Some of the most important uses at the present time are for the production of cement at Daudkhel, ammonium sulphate at the Pak-American Fertilizer Plant at the same location, and electricity at the 15-mw Quetta Steam Station (commissioned in September 1964).

Details of the known coal fields in West Pakistan are given in Table 3A-2, which indicates that total reserves may have a thermal value of the order of 6,000 trillion Btu. However, this reserve figure does not appear to be directly comparable with the reserve figure given for natural gas. Reserve figures for gas and oil generally include only deposits which are believed recoverable with present technology and at a price that might make recovery economic within the foreseeable future. By contrast reserve estimates for coal generally cover all known deposits, irrespective of the cost that may be involved in recovery. If West Pakistan's coal reserves were quoted in terms of the same concepts used to define gas reserves they would be substantially less than shown above.

Apart from the coal fields around Quetta, the main field which could become important for power generation, as far as can now be foreseen, is the Lakhra field (some 85 miles northeast of Karachi in Dadu District) which was discovered during the Second Plan period. Table 3A-2 indicates that the quality of coal at Lakhra is lower than in most of the other fields in West Pakistan; it is rather lignite than coal. However, the field is apparently much larger than those previously known and somewhat more accessible. Reserves are currently estimated at 130 million tons; the coal has a high moisture content of about 35 percent. The depth of the seam below the surface is unclear. In a letter to WAPDA the Directorate of Mineral Development of the West Pakistan Government indicates that the coal seam is "not more than 500 feet" below the surface anywhere in the field. According to the Third Plan document the field is already being mined at Lailian and there the seams occur at depths of 80 to 240 feet below the surface.

Oil Reserves

Least significant of the known energy-producing mineral reserves in West Pakistan is oil. The exact extent of the oil reserves is unclear but ECAFE uses an estimate of 27 million barrels—equivalent to about 160 trillion Btu's in terms of thermal value. This estimate is probably on the low side. At present, exploitation is largely confined to 4 small fields in the Potwar Plateau in the north of the Province—Dhulian, Khaur, Joya Mair, Karsal and Balkassar. The most important of these is Dhulian, where oil was found in 1937 in the Laki limestone at 7770 feet, in 1952 in the Ranikot limestone 800 feet deeper, and in 1960 in a Jurassic horizon deeper still. The field is exploited by the Attock Oil Company which also operates a refinery at Morgah, near Rawalpindi. Output of refined products at Morgah from Potwar crude has expanded quite rapidly—reaching about 500,000 tons in 1965—or double the 1955 level. Half a million tons is approximately the full capacity of the refinery.

Since the Potwar oil fields still meet only about 25 percent of total provincial requirements of petroleum products, and petroleum imports represent a significant foreign exchange burden, considerable exploration efforts have been made in recent years but they have not resulted in any important discoveries. Prospecting and drilling have been carried out both by private companies and by the Government's Oil and Gas Development Corporation. One of the most hopeful sites identified by surveys undertaken during the Second Plan period was Tut, 90 miles west of Rawalpindi; however, the first well has now reached beyond 13,000 feet without result.

Besides Morgah, West Pakistan has two other oil refineries, both located in Karachi and both using imported crude. The Pakistan Refinery, whose main products are fuel oil, high speed diesel oil, kerosene, motor spirit and jet petroleum, came into operation in 1963. At present it cannot find a market for all of its products in West Pakistan, so that in 1965/66, it exported about $5 million worth of fuel oil and naphtha. The other refinery—National Refinery—which is in the public sector and is also located at Korangi close to Karachi was opened in 1966. It has an initial capacity to produce about 0.5 million tons of petroleum products, whereas the Pakistan Refinery has a current capacity of about 2.5 million tons.

Total Mineral Fuel Reserves

Simple addition of the reserve estimates discussed above indicates that West Pakistan has known mineral fuel resources with an estimated thermal value of a little more than 16,000 trillion Btu's. Table 3A-3 summarizes the estimates and compares them with current annual offtakes. These figures must, however, be treated with great care because, as pointed out above in connection with the coal reserves, the estimates for the different minerals are based on different concepts. Nevertheless, the table does bring out clearly the dominant position of natural gas; and if figures were available on the fuel reserves which are likely to be economic to recover, this same conclusion would stand out even more clearly.

Even the figure for gas reserves, however, is not free of complications. It seems to be made up of an amalgam of different figures for different fields; for instance, the figure for Mari includes proven, probable and possible reserves, while the figure for Sui apparently represents proven reserves. Moreover, the total figure used above includes fields such as Dhulian, where the daily offtake is limited, and fields such as Uch where location or the quality of the gas may preclude economic exploitation. In view of these uncertainties, we have generally adopted for the purposes of this Report one 'firm' figure for readily usable gas reserves—about 7,200 trillion Btu (including Sui, Mari, Sari Sing, Khandkot and Mazarani) and one 'higher' figure of about 9,500 trillion Btu (on the assumption that an additional two-three trillion cubic feet of gas might be discovered at, say, Sui).

TABLE 3A-3
CURRENT ESTIMATES OF MINERAL FUEL RESERVES AND ESTIMATED ANNUAL CURRENT OFFTAKES
(Trillion (10^{12}) Btu's)

	Reserves	1964 Current Offtake
Natural Gas	10,000	53
Coal	6,000	27
Oil	200	20
	16,200	100

The Adequacy of Reserves

If the figures in Table 3A-3 are taken at face value they would imply that West Pakistan has mineral fuel reserves sufficient to cope with the current level of demand for more than 150 years—and reserves of natural gas sufficient to cope with current demands for gas for nearly 200 years. This would seem extremely ample in the context of the United States, where proven reserves of natural gas for example are currently sufficient to sustain present levels of consumption for only about 15–20 years. There the historical experience of continuing discoveries of additional reserves in developed fields and of new gas fields has generated a high degree of optimism about the country's ability to meet future demands for gas for considerably more than 20 years.

However, there are various characteristics of the situation in West Pakistan which counsel a rather more cautious attitude toward the Province's mineral fuel reserves. In the first place, the effects of a shortage in domestic supplies of energy, if it were to occur, would be more severe than it would be in some other countries because of the stringency of the foreign exchange situation in West Pakistan. Indigenous fuel reserves are somewhat limited in range, as has been shown, and West Pakistan still has to meet about a third of its total commercial fuel requirements from imports at present despite considerable efforts at import substitution in this sector. In the second place the demand for commercial fuels is growing very rapidly—more than 10 percent per annum compared with about 4–5 percent, for instance, in the U.S.—and this growth may be expected to continue since it is typical for a country at the stage of development now reached by West Pakistan. In the third place there is more uncertainty about the reserve figures used here than about the proven reserve figures mentioned for the United States. Many of the gas structures in Pakistan have been tested with only one or two wells and then held in reserve for a time when an opportunity to use them economically may arise: the reserve estimates may obviously change substantially when the structures are more fully investigated. Moreover, the recoverability of reserves from a field and the feasible rate of recovery depend on a number of factors, not yet fully known, such as the reservoir pressure. It would be unjustified to infer that no additional undiscovered reserves exist. Nevertheless experience during the 1960's does raise doubt about the 1959 estimates of 5 trillion cubic feet of gas in untested structures which was cited above. As pointed out, the main development during the Second Plan in connection with natural gas reserves was a very substantial reduction of the estimates of Mari reserves as a result of further drilling and testing.

SUPPLY TRENDS AND ANTICIPATED DEMAND

The future demand for electricity has been examined in considerable detail in Supplemental Paper No. 2, but an essential preface to an evaluation of the proper economic price to be attached to fuel in the preparation of a long-term plan for the development of the electric power sector is an examination of the overall balance of supply and demand for energy.

Recent Trends in Commercial Supply of Energy

Two noteworthy features have characterized the growth of energy consumption in West Pakistan since Independence—the rapidity with which consumption of commercial supplies of energy has grown relative to the rate of growth of GNP and the increasing extent to which this energy has been supplied from domestic sources. ECAFE has estimated that consumption of commercial supplies of energy in the whole of Pakistan grew between 1951 and 1961 at an annual rate of about 7.5 percent—more than two and a half times the rate of growth of GNP. Some estimates have been compiled from a variety of sources for West Pakistan alone and they are shown in Table 3A-4. Some of the figures are little more than informed guesses, since the data, especially on imports, are extremely deficient. Nevertheless, the figures are reasonable indicators of orders of magnitude. Table 3A-5 represents the same data converted into standard thermal units (British thermal units). It suggests that in West Pakistan the consumption of commercial supplies of energy increased between 1949 and 1964 at an annual rate of better than 10 percent—or again about two and a half times the rate of growth of GNP. The other important trend which stands out from the recent experience is the extremely rapid rate of growth of domestic production of commercial energy. ECAFE assesses this at 16 percent per annum between 1951 and 1961 on an all-Pakistan basis. Table 3A-5 suggests that the same rate applies to West Pakistan over 1949–64.

The figures in Table 3A-4, however, contrast with ECAFE's estimates in that they suggest that West Pakistan is significantly more self-supporting in energy than Pakistan as a whole. The Table shows that West Pakistan met more than 60 percent of its commercial energy requirements from domestic supplies in 1964; ECAFE has a figure of about 40 percent domestic supplies for the whole of Pakistan in 1961. It is quite credible that West Pakistan should be much more self-supporting than East Pakistan since the West Wing contains the country's main exploited reserves of coal and oil and the development of natural gas production has been much more significant there than in the East. Table 3A-5 brings out the great importance of natural gas among West Pakistan's supplies of energy; it grew in 10 years from almost nothing to nearly 30 percent of total commercial energy supplies.

TABLE 3A–4
ESTIMATED CONSUMPTION OF COMMERCIAL ENERGY IN WEST PAKISTAN, 1949–64[a]

	1949	1955	1960	1964
Domestic Sources				
Coal ('000 metric tons)	340	540	830	1,215
Petroleum ('000 metric tons)	130	290	365	500
Natural gas (MMcf)	—	1,380	29,560	53,360
Hydro energy (Mill. kwh)	7	310	540	1,370
Imported				
Coal ('000 metric tons)	600	200	400	300
Petroleum products ('000 metric tons)	160	1,230	1,090	1,400
Energy in form of electricity (Mill. kwh)	200	780	1,690	3,390

[a] Excluding petroleum products used as lubricants, but including gas used as feedstock for the production of fertilizer.

Sources: Mainly CSO statistical bulletins and Pakistan trade statistics, supplemented by WAPDA data, Planning Commission documents and various consultants' reports.

TABLE 3A-5
THE CALORIFIC VALUE OF COMMERCIAL ENERGY CONSUMED IN WEST PAKISTAN, 1949–64[a]
(trillion (10^{12}) Btu's)

	1949	1955	1960	1964
Domestic Sources				
Coal	7.5	11.9	18.3	26.7
Petroleum	5.2	11.6	14.6	20.0
Natural Gas	—	1.3	28.8	52.5
Hydro-energy	0.1	4.7	8.1	20.6
Subtotal	12.8	29.5	69.8	119.8
Imported				
Coal	20.8	5.2	10.4	7.8
Petroleum Products[b]	6.4	49.2	43.6	56.0
Subtotal	27.2	54.4	54.0	63.8
Total	40.0	83.9	123.8	183.6
of which, electricity	3.0	11.7	25.4	50.9

[a] The following conversion rates have been used:
domestic coal: 22 mill. Btu/metric ton (10,000 Btu/lb.).
domestic and imported petroleum: 40 mill. Btu/metric ton
natural gas: Sui gas @ 975 Btu/cu. ft.
Dhulian gas @ 1,100 Btu/cu. ft.
imported coal: 26 mill. Btu/metric ton (12,000 Btu/lb.).
[b] Including products refined in the Karachi Refinery from imported crude.

Role of Electricity and Primary Sources of Generation

Table 3A-5 suggests that electricity has risen from about 8 percent of total supplies of commercial energy in West Pakistan in 1949 to about 28 percent in 1964. The power consultant estimates total electricity generation in 1964 (including industrially owned generators) at about 3.4 billion kwh. This is equivalent to about 50 trillion Btu's. The primary sources responsible for this generation were mainly natural gas (about 23 trillion Btu's or 40 percent of total gas supply went directly to the power utilities[1] and hydro plants (about 20 trillion Btu's, as indicated in Table A1-5. The main primary source accounting for the remainder was probably petroleum products such as diesel oil and fuel oil. Actual figures are only available on fuel consumption by KESC and WAPDA and they show oil providing only about 1 trillion Btu's. However, most of the industrially owned generating plants belonging to the smaller utilities have been fired by diesel oil, though they are now increasingly converting to natural gas as it becomes available. Coal is a very minor primary source in the generation of electricity; the main coal burning plant in WAPDA's new unit at Quetta which consumed less than 20,000 tons of coal or about 0.25 trillion Btu's in 1964/65. Hydro-energy is converted into Btu at a rate of 15,000 Btu/kwh which represents approximately the average fuel consumption of generators in West Pakistan per kwh sent out at the present time.

[1] 20 trillion Btu's of actual sales were to the power utilities. Three are added to cover purification of the gas and shrinkage.

Fuel Imports

The foreign exchange burden of the fuel imports given in Tables 3A-4 and 3A-5 is hard to identify but it is probably in the order of Rs. 120 million (about $25 million) or about US cents 40/mln Btu. The Third Plan document states that fuel imported for the whole of Pakistan cost about Rs. 446 million in 1963/64. The CSO trade statistics indicate a figure of about Rs. 300 million for imports of coal and petroleum products in that year, Rs. 200 million for 1964/65 and Rs. 210 million for 1965/66. West Pakistan's share of these imports is given as Rs. 167 million, Rs. 80 million and Rs. 83 million in each of these fiscal years, respectively. These figures include nonfuel petroleum products such as lubricating oil and they appear to exclude crude oil imported for production of petroleum products at the refineries in Karachi. Allowing for these items, we can estimate that West Pakistan's foreign exchange bill for fuels in 1964 was about Rs. 15 million for coal and coke, and about Rs. 105 million for petroleum and petroleum products. Most of the petroleum imports took the form of imports to the refinery. The price of crude oil imported is in the neighborhood of 30 cents/million Btu. Refined petroleum products appear to be imported at much higher prices. The price of imported coal appears to be about 40 cents/million Btu. A total bill of about Rs. 120 million for imported fuel would imply that fuel imports made up about 3 percent of West Pakistan's total imports from abroad (including invisibles) in 1964.

Recent Trends in Total Energy Supply

The figures given so far cover only a relatively small proportion of the total supply of energy in West Pakistan; they exclude noncommercial fuels such as wood, charcoal, cotton stalks and dung which undoubtedly make a very large contribution to the total supply of energy in the Province. Accurate estimates of noncommercial energy supplies are impossible to make. Detailed studies of various countries in the Middle East and Asia prepared some years ago[1] suggest that, of 8 countries where data are available, 5 had consumption levels of about 250 kilograms of coal equivalent (or 6.7 million Btu's) per capita of noncommercial energy in the early 1950's.

What historical evidence is available from different countries suggests that it is reasonable to assume that total energy consumption grows at about the same rate as GNP. When allowance is made for the increasing efficiency with which primary energy sources such as coal and gas are converted into useful energy, this means that total energy consumption grows slightly faster than GNP. At the same time the composition of the energy consumed tends to shift markedly away from noncommercial sources towards more efficient converters such as coal, oil and gas. The consumption of electricity tends to grow much faster than the consumption of other fuels because of its efficiency, versatility and cleanliness.

What information is available suggests that West Pakistan is no exception to these general trends. Table 3A-6 has been drawn up with the aid of the figures on commercial energy supplies developed in Table 3A-5 and on the basis of the

[1] M. Hartley, "Energy as a Factor in the Progress of Underdeveloped Countries," Proceedings of the U. N. Conference on New Sources of Energy (Rome, 1961), United Nations, New York, 1963.

assumption that noncommercial energy supplies were about 6.7 million Btu's per capita in 1949 and have since been growing at about the same rate as the rural population.[1] The resultant estimates of total energy consumption suggest that it has been growing at about the same rate as the GPP of West Pakistan, in constant price terms. The Table also indicates the rapidly increasing share of electricity in the total supply of energy in the Province.

Future Trends

Future Trends in the Demand for Energy. On the basis of the figures worked up in Table 3A-6 and with the assumption that supplies of noncommercial energy will continue to increase at about the same rate as rural population, it is possible to make some rough estimates of the future demand for commercial energy that is implied by Pakistan's Perspective Plan. The GPP growth rate for West Pakistan envisaged in the Perspective Plan is about 6 percent per annum. Table 3A-7, which parallels Table 3A-6 except that demand for commercial energy is derived as a residual, is based on this rate of growth in provincial product. These figures suggest that demand for commercial supplies of energy may increase at an average rate of nearly 9.5 percent per annum over the Perspective Plan period. Total demand for energy may increase from about 10 million Btu per capita in 1964 to nearly 20 million Btu per capita in 1985. Commercial energy requirement may rise from about 37 percent of the total in 1964 to over 70 percent of the total in 1985. The last two lines of the Table are based on the main power load forecasts that have been used in these studies (Supplemental Paper No. 2). They suggest that the per capita demand for electricity may increase about four and a half times between 1964 and 1985 and that electricity; even with allowance for substantial improvement in the average efficiency of thermal generation, may increase from about 10 percent of total energy requirements in 1964 to more than 20 percent in 1985.

[1] Here defined as the population living in places of less than 25,000 inhabitants.

TABLE 3A-6
ESTIMATE OF TOTAL SUPPLY OF ENERGY IN WEST PAKISTAN, 1949–64

	1949	1955	1960	1964
Total Population (mill.)	34.0	39.6	45.0	49.9
Rural Population (mill.)	29.6	34.0	37.6	40.6
Energy (trillion Btu's)				
Noncommercial	230	264	292	315
Commercial	40	84	124	184
Total	270	348	416	499
GPP (Rs bill. 1959/60 prices)[a]	11.6	14.2	16.6	20.8
Energy per capita (mill. Btu's)	7.9	8.8	9.2	10.0
Electricity per capita (kwh)	6.0	20.0	38.0	68.0
Electricity as % of total energy	1.1	3.4	6.1	10.2

[a] See Paper I for estimate of GPP.

TABLE 3A-7
PROJECTION OF DEMAND FOR ENERGY IN WEST PAKISTAN, 1964–85

	1964	1970	1975	1980	1985
Total population (mill.)[a]	49.9	58.3	67.0	78.0	89.0
Rural population (mill.)	40.6	45.7	50.7	57.0	62.1
GPP (PRs blns, 1959/60 prices)[a]	20.8	29.2	39.7	55.4	71.9
Energy (trillion Btu's)					
Total	499	710	950	1,270	1,700
Non-commercial	315	355	394	441	480
Commercial	184	355	556	829	1,220
Energy per capita (mill. Btu's)	10.0	12.2	14.2	16.3	19.1
Electricity per capita (kwh)	68.0	130.0	197.0	258.0	331.0
Electricity as % of total energy[b]	10.2	15.0	18.0	20.6	20.8

[a] See Supplemental Paper No. 1 for population and income projections.
[b] Growth of electricity appears smaller here than in preceding line because of the assumption that average heat rates per kwh sent out will improve from about 15,000 Btu in 1964 to about 12,000 Btu per kwh sent out in 1985.

The Future Supply of Energy. The first section above gave some details of the current estimates of West Pakistan's energy reserves and Table 3A-5 indicated trends in the supply of different forms of energy. Therefore it is possible to use what is currently known about West Pakistan's energy situation to make some rough predictions as to the primary sources of energy that will meet the demands projected above.

Special attention will be given to natural gas because of its predominant importance among West Pakistan's mineral fuel reserves and because its use has been growing much more rapidly than that of any other fuel. It has significant operating advantages over other fuels and a wide range of potential uses. It is, moreover, the main existing and potential alternative to water as a primary source of electricity generation.

The Use of Natural Gas

The main consumers of gas to date have been the power utilities and the second most important consumer has been the cement industry. Most of the cement plants in West Pakistan now use gas for firing their kilns. Table 3A-8 indicates the pattern of gas consumption in 1964.

The current pattern of consumption fails to bring out the importance of gas to many industries. Gas has significant operating advantages for a number of industries,[1] but it is especially important in the production of certain goods for which it is used not only for its heating value but also for its chemical content. By far the most important of these goods at the current stage of development in West Pakistan is fertilizer, for which demand in the Province is growing rapidly. At

[1] Even where natural gas is used purely for heating purposes it can have substantial advantages over other fuels. A.U. Loan reports, for example, that experiments carried out prior to and after the conversion of the Indus Glass Factory at Hyderabad and the Crescent Glass Factory in Karachi from oil to gas established that to make one ton of glass requires 19.4 million Btu's with furnace oil and only 12.3 million Btu's with Sui gas. (A.U. Loan, "The Last Ten Years of Natural Gas in Pakistan," November 1965.)

TABLE 3A-8
NATURAL GAS SALES IN WEST PAKISTAN, 1964
(MMcf)

Industry	Sui	Dhulian	Total	% of Total
Power	19,666	618	20,284	45.1
Cement	7,923	1,909	9,832	21.8
Fertilizer	2,635	—	2,635	5.9
Other Ind.[a]	10,605	784	11,389	25.3
Commercial	538	3	541	1.2
Domestic	351	1	352	0.7
	41,718	3,315	45,033	100.0

[a] Approximately 50 percent of these sales are to the textile industry. Glass industry accounts for about 20 percent of sales to other industries.

present the use of gas for production of fertilizer is confined to the relatively small Multan plant which produces ammonium nitrate and urea. However, gas of the quality available at Sui and Mari is very suitable for the manufacture of nitrogenous fertilizer. A large urea plant is currently under construction at Dharki close to Mari and three or four additional nitrogenous fertilizer projects are in the planning stage. Another potential priority use for gas is in the production of petrochemicals. Known natural gas reserves are lean—they have a relatively small proportion of the heavier hydrocarbons such as methane and propane in their chemical composition—and, since naphtha and refinery gas will continue to be available from the Karachi refineries, it will probably not be economical to use the natural gas to produce ethylene, the basis of one large range of chemical products. However, both Sui and Mari gas have a sufficient methane content to be transformed into acetylene which is the basis of a wide range of chemicals, such as polyvinylchloride, polyacrylonitrile, methanol and polyacetates. In addition the gas could be used in conjunction with urea from, say, the Multan plant to manufacture urea formaldehyde, plastic and adhesives. Some of these goods are already being produced from Sui gas and there are plans for producing others which will no doubt be executed when the market for them looks sufficiently large to justify plants of economic size. These uses of gas are obviously important because of the peculiar advantages of gas as a basis for production of certain petrochemicals, but the bulk of the growth in demand for gas will come from the fertilizer industry and from general industrial consumers.

Projection of Nonelectrical Demand for Natural Gas

To provide a firmer picture of the potential role of natural gas in meeting future energy demands, and to gain insight into the extent to which gas may be used for generation of electricity without prejudicing its availability to other consumers, detailed projections have been made of nonelectrical demand for gas in West Pakistan up to 1985. These projections are based on those prepared by the gas transmission companies, Sui Gas Transmission Company (and the distribution companies, Karachi Gas and Indus Gas) for the Southern Region and Sui Northern Gas Pipelines Limited for the North. Their projections are made largely for purposes of financial planning and so they tend to the conservative. To ensure that adequate allowance is made for the growth of demand for natural gas for purposes other than power generation we have adopted the higher versions of their projections (e.g., those of KGC and IGC rather than of SGTC for the South) and we have further adjusted them by making special allowance for increases in consumption by major gas consuming industries (e.g., cement and fertilizer) in the long run. Appendix Tables 3-1 and 3-2 represent these adjusted versions of the gas companies projections (omitting the electric utilities). Besides expansion of existing fertilizer plants, plans also exist to construct additional fertilizer capacity. This capacity will be needed to meet the projection of fertilizer requirements given elsewhere in this report and so a further allowance must be made in the gas projections to accommodate these plants. Appendix Table 3-3 is a projection of fertilizer production designed to do somewhat better than meet the minimum target of supplying about 30 lbs. of nitrogen per acre on 110 percent of total cultivated acreage of 30 million acres in 1975 and 50 lbs. of nitrogen per acre on 140 percent of total cultivated acreage of 30 million acres in 1985. The last two lines of Appendix Table 3-3, under the heading "Additional Capacity Required" indicate the fertilizer plants anticipated whose gas requirements are not included in Appendix Tables 3-1 and 3-2. One 400,000-ton urea plant (184,000 tons of N) is indicated for Khandkot because the Government plans a plant there. Two other 500,000-ton urea plants (230,000 tons of N) are indicated for Mari/Sui. The gas requirements of these plants, in terms of Sui-quality gas (about 60,000 cu.ft. of Sui gas per ton of N excluding gas required for electric supply)[1] would be about 30 MMcf/day in 1975, 70 MMcf/day in 1980 and a little over 100 MMcf/day in 1985.

These various calculations are summarized in Table 3A-9, below, which indicates the 1964 average daily sales of Sui gas to entities other than the electric utilities and shows the projections for the key years 1970, 1975, 1980 and 1985. This Table does not indicate the full contribution that natural gas may make toward meeting energy requirements in coming years. There are two additional small items

[1] 60,000 cu.ft./long ton of N is less than the consumption of the existing fertilizer plants in West Pakistan. Their requirements are about 80,000 cu.ft of Sui gas/long ton of N. New plants should be more efficient.

TABLE 3A-9

AVERAGE DAY SALES OF SUI GAS (EXCL. SALES TO ELECTRIC UTILITIES), 1964–85[a]

(MMcf/day)

	1964	1970	1975	1980	1985
Average Daily Sales (MMcf/day)					
SNGPL	12	54	164	210	270
SGTC	49	102	165	222	296
Additional Fertilizer Projects	—	—	30	70	105
Total	61	156	359	502	671
Annual Total ('000 MMcf)	22.3	56.9	131.0	183.0	245.0
Sui Gas Off-take ('000 MMcf)[b]	25.2	64.3	148.0	207.0	277.0
Thermal Value[c] (10^{12} Btu)[d]	25.0	63.0	144.0	202.0	270.0

[a] All figures are given net of availability from Dhulian assumed to be 12 MMcf/day.
[b] Offtake represents Line 5 increased 13 percent to allow for purification and compression fuel, etc.
[c] Thermal value taken at 975 Btu/cu. ft.
[d] (10^{12} Btu = trillion Btu).

which have to be taken into account, apart from sales to electrical utilities. One is the contribution of the Dhulian field, offtake from which is limited by technical factors as pointed out before to a daily average of 12 MMcf. On this basis, consumption from this field might rise from about four trillion Btu's in 1964 to about five trillion Btu's annually. The Table also omits some fertilizer production. For the sake of simplicity, rather than to indicate reality, the assumption has been made that all new fertilizer plants will be based on Sui gas. However, as pointed out above, there is already one fertilizer plant under construction close to Mari. This plant will have a capacity of 175,000 tons of urea per year or about 80,000 tons of N. The requirement of Mari gas per ton of N, excluding requirements for generation of electricity, is about 80,000 cubic feet or 60 million Btu's. Therefore, this plant will require about five trillion Btu's per annum for feedstock and reformer furnace. These two small items are additional to the figures in Table 3A-9.

Other Energy Sources

The main existing sources of commercial energy apart from gas are imported fuels, coal and oil. It is hard to foresee how supplies of these will develop. Demand for petroleum products will undoubtedly grow rapidly and the estimate of oil reserves given in the first section suggests that it will not be possible to increase domestic production to meet demand. Indeed currently estimated reserves of oil are insufficient to sustain present production for more than about 10 years. But if it is assumed that these reserves are underestimated so that at least the current level of production could be maintained, then domestic petroleum production might continue to contribute 20 trillion Btu's a year through 1985 to meet domestic energy requirements. Little is known about the potential for increasing the production and consumption of coal. However, coal production has been growing quite rapidly in recent years—at about 10 percent per annum since 1950—and estimated recoverable reserves are sufficient to sustain this increase for some time. We might assume therefore that coal supplies will continue to increase at about 10 percent per annum. Finally, there is imported fuel. Tables 3A-4 and 3A-5 indicated a sharp decline over the last 10 years in imported fuels' share of the total energy market in West Pakistan. Nevertheless in absolute terms fuel imports have continued to grow. It was estimated above that they constituted about 3 percent of total imports from abroad in 1964 and that the average price was about 40 cents/million Btu. It is assumed, for present purposes, that West Pakistan will continue to spend about 3 percent of available foreign exchange on fuel imports and that the average price of this fuel will gradually decline[1] as more of the imported energy takes the form of crude oil for production of refined products at the Karachi refineries. Then we can make an estimate of the potential contribution to energy supplies from this source over the next 20 years. These estimates are drawn together below.

The Overall Energy Balance

On the basis of these projections and assumptions it is possible to draw up a rough fuel balance sheet for the Perspective Plan period. Lines 1-3 of Table

[1] Actual assumption made here is that average price of imported fuel will decline as follows: 1964—40¢ per million. Btu; 1970—38¢; 1975—36¢; 1980—34¢; 1985—32¢.

3A-10 show total energy requirements, non-commercial supplies and, as a residual item, requirements of commercial energy (see Table 3A-7). Lines 4-6 indicate the contributions of the various thermal fuels discussed above to meeting commercial energy requirements. Line 7 is based on information developed in subsequent papers and indicates the hydroelectric contribution to total energy supplies implied by a program which includes the completion of Tarbela in 1975. Line 8 is also based on the power program which includes Tarbela in 1975 and is recommended in this report; it represents approximately the draft on the Province's natural gas resources that might be made in the various years by the electric utilities. Line 10 is added to allow imports of fuel to grow at 3 percent per annum. Line 12 is the residual. Line 13 is for comparative purposes; it indicates the amount of energy that will be consumed in the form of electricity according to the Main Load Forecast used in these studies.

The table suggests that it is possible to foresee a reasonable balance in the supply and demand for energy in West Pakistan over the Perspective Plan period. However, the 'gap' which is the amount of energy apparently required to meet the targets of the Perspective Plan, the source of which cannot be foreseen, grows quite rapidly so that by the end of the Plan period it is of the same order of magnitude as total energy imports. The table indicates the dynamic growth in natural gas that can be anticipated: from about 10 percent of total energy supplies in 1964 to about 20 percent of total energy supplies in 1985. If Tarbela were not in existence by 1985 and gas-fired thermal plants were supplying approximately the energy contribution that is assumed in the Table to come from Tarbela in that year,

TABLE 3A-10
PROJECTIONS OF ENERGY REQUIREMENTS AND SUPPLIES, 1964-85
(trillion Btu's)

	1964	1970	1975	1980	1985
1. Total Requirements	499	210	950	1,270	1,700
2. Noncommercial	315	355	394	441	480
3. Commercial Requirements	184	355	556	829	1,220
Commercial Supplies					
4. Natural Gas (Nonelectric)	30	73	154	212	280
5. Domestic Coal	27	47	76	123	200
6. Domestic Petroleum	20	20	20	20	20
7. Hydro[a]	20	74	110	200	213
8. Gas (Electric utilities)	23	30	45	50	55
9. Total Domestic	120	244	405	605	768
10. Imports	64	96	126	175	230
11. Total Commercial	184	340	531	780	998
12. Energy Gap	—	15	25	49	222
13. Energy Consumption in form of electricity[b]	(58)	(103)	(199)	(262)	(335)

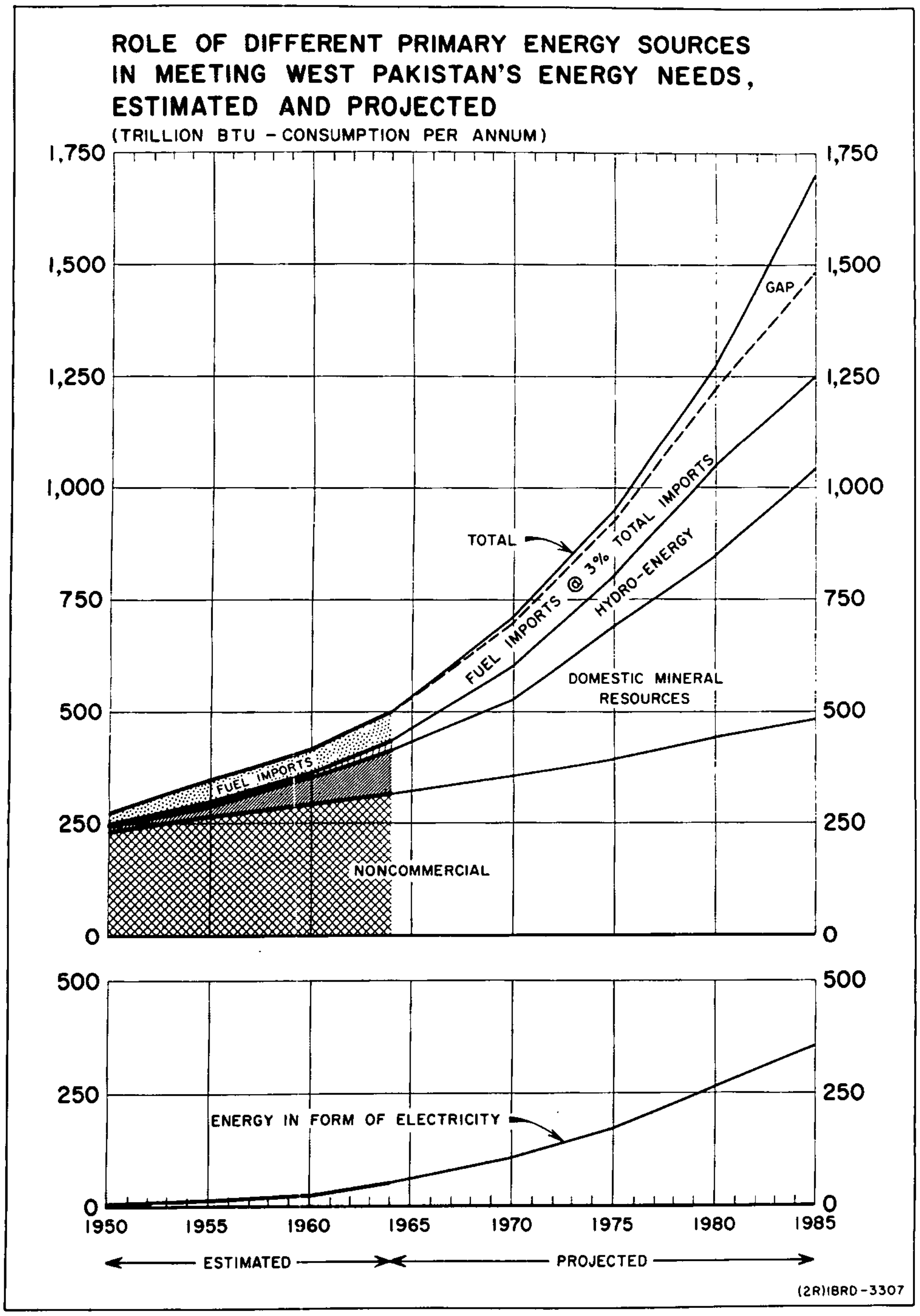
[a] The energy contribution from hydroelectric plant is calculated on the basis of conversion rates which are supposed to represent approximately the average efficiency of thermal generation in West Pakistan at the various dates, i.e., 1964—15,000 Btu/kwh, 1970—14,000 Btu/kwh, 1975—13,000 Btu/kwh, 1980—13,000 Btu/kwh, 1985—12,000 Btu/kwh.

[b] Forecast discussed in Supplemental Paper No. 2. Includes industrial generation as well as utilities' generation. It is converted into thermal value at the rates indicated in footnote [a].

then gas would be providing an additional 120 trillion Btu's or altogether 27 percent of total energy requirements.

Figure 3-1, below, represents in pictorial form the past history shown in Table 3A-5 and the projections shown in Table 3A-10.

VOLUME III
FIGURE 3.1



THE EFFECT OF SUPPLY AND DEMAND ON THE PRICE OF THERMAL FUEL

The Study Group's investigations revealed as outlined above in this paper that it was possible to foresee a reasonable balance between the domestic demand for energy in West Pakistan and the supply of energy over the next 10–15 years, on the assumption that fuel imports would remain at about 3 percent of total imports. Towards the end of the Perspective Plan period, however, imports might have to rise above this level if no new fuel reserves were to be discovered in the meantime. Natural gas would be the most rapidly growing domestic mineral source of energy.

In the overall energy projections that are presented in this Paper, it was assumed that the hydroelectric projects recommended in this report would be undertaken and that some natural gas would be used for thermal generation of electricity. However, natural gas is also the main foreseeable alternative to hydro plant as a source of electric energy in West Pakistan. For purposes of assessing the value of the Province's natural gas reserves (and subsequently, the value of the hydroelectric projects) it is useful to consider the implications of a conservationist decision to reserve all the natural gas deposits for nonelectrical uses. The reserve estimates given earlier showed a total thermal value of gas reserves of about 10,000 trillion Btu. However, there is doubt about the extent to which the relatively small fields—Uch, Khairpur and Zin—could in fact be brought into use economically. Moreover, the usefulness of the relatively large reserves at Dhulian is limited by the low daily offtake that is technically possible; the availability from Dhulian was deducted from the nonelectrical demand projections shown in Table 3A-9 of this Paper. Thus, the reserves appropriate for comparison with estimated requirements are those in the remaining five fields, or about 7,300 trillion Btu. Total withdrawals from these fields for nonelectrical purposes, as projected in Table 3A-11 would account for about 3,100 trillion Btu by 1985; this Table also showed consumption running at the level of about 275 trillion Btu per annum by that year. Therefore, if a strictly conservationist view were taken, and all the natural gas available to West Pakistan were reserved for nonpower uses the reserves as currently estimated would be sufficient to sustain consumption to about the year 2000, provided that no new commitments were made after about 1985.[1] If we take a slightly more optimistic view of reserves and assume, say, that the Sui field is somewhat larger than now believed, so that total reserves are of the order of 9,500 trillion Btu, then this would suffice to prolong consumption at the 1985 level for a further eight years to about 2008, provided that all gas was reserved for nonelectrical use.

What is the implication of these trends in nonelectrical demand for gas for the Study, particularly for the power development program? Should the natural gas reserves really be conserved for nonelectrical use and, if so, to what extent? How far would the answer to this question be changed by a change in the estimate of natural gas reserves? What will be the cost to Pakistan of exceeding the 'acceptable' level of 3 percent of total foreign exchange expenditure for fuel imports? Some better perspective on the alternatives available may be had by expressing the relationship between supply and demand in terms of economic price trends as distinct from actual prices.

[1] Assuming approximately a 15-year commitment, comparable with a 15-year life for many of the relevant gas-consuming types of plant.

Current Financial Price of Natural Gas

The price actually charged to the consumer for natural gas has fallen substantially over the years as a result of increasing demand bringing the lower levels of the slab-pricing structure (e.g., Appendix Tables 3-1 and 3-2) into operation and as a result of across-the-board price reductions. It now compares very favorably with the price of imported fuel oil in locations reached by the gas pipeline, as indicated in Table 3A-11. The Table indicates that the slab-pricing system under which KESC receives gas results in an average price of about Rs. 1.70 (37 cents) per million Btu (compared to about Rs. 2.00 (42 cents) per million Btu in 1960/61), while the agreement under which WAPDA receives gas for its Multan (and in future Lyallpur) plants results in an average price of about Rs. 2.30 (48 cents) per million Btu. Nevertheless, the saving to WAPDA from using gas is considerably greater than the comparable saving to KESC because of the high costs of rail transportation of imported fuel oil. The price structures established for major consumers equally result in much greater savings from the use of gas in the North than in the South.

The Price of Gas for Planning Purposes

It would be possible to plan for the development of the power sector on the basis of the current financial fuel prices discussed in the preceding paragraph. However, these prices do not provide a very solid basis for planning 10 or 20 years into the future. In the first place they may change at any time—as they have been changing over the years since the gas fields were first developed. In the second place, and much more important, these financial prices cannot be related in any meaningful way to the broader questions of fuels policy raised earlier in

TABLE 3A-11
DELIVERED PRICE OF FUEL OIL AND NATURAL GAS[a]
(Rs. per million Btu)

Location	Fuel Oil	Natural Gas			
	Current 1964/65[b]	Average: General	Average: KESC and WAPDA	Price Structure for Major Consumers: Max.	Price Structure for Major Consumers: Min.
Karachi	2.87	2.17[c]	1.70	2.30	1.28
Sukkur (Mari)	3.44	2.41[d]	2.00	n.a.	n.a.
Multan	3.80	2.29	2.30	2.87	2.10
Lyallpur[e]	3.93	2.29	—	2.87	2.10

[a] A straight comparison between the prices of fuel oil and natural gas in terms of Rs. per million Btu to some extent exaggerates the price for gas, which has been found to be thermally more efficient for many purposes. KESC has established that, for its purpose, gas is overall 4 percent more efficient than fuel oil, while for many other purposes the difference is even greater; experiments have shown, for instance, that Sui gas is 36 percent more efficient for glassmaking.

[b] Current prices, including tax 1964/65, as given in A.U. Loan "The Last Ten Years of Natural Gas in Pakistan" (November 1965).

[c] 1964.

[d] 1963.

[e] Lyallpur was not in fact connected to the gas supply system until 1965; the gas-fired generators at Lyallpur are only coming into operation during 1967 but the price structure for gas supply was agreed between WAPDA and SNGPL some time ago.

this Paper. What is required for purposes of long-term planning is some procedure which recognizes that mineral fuel reserves are an exhaustible resource and indicates a sensible way of rationing out the known reserves over the years. The key problem is to define what West Pakistan loses when a cubic foot of gas is burned up—or, in other words, the cost of the economy in terms of opportunities foregone as a result of burning this cubic foot of gas.

It was with a view to approaching a tentative solution of this problem that considerable attention was devoted in the course of the Study to trying to establish prospective demand for natural gas for non-electrical purposes and the amount of time that the natural gas deposits would last if reserved entirely for such purposes. The gas fields can reasonably be conceived as being made up of a number of successive layers which will be consumed one by one over the years until the reserves are exhausted. The projections prepared suggested that, if the reserves of all the main gas fields as currently estimated were reserved for non-electrical use, they would last till about the year 2000, when the last layer of 275 trillion Btu would finally be used. The result of using gas in the interim for power generation will therefore be to eat into this bottom layer and force West Pakistan to import some other fuel in 2000 to the same order of magnitude of thermal value as the gas consumed. If interim consumption of gas for power generation aggregates less than 275 trillion Btu then only the layer which had been reserved for 2000 will be affected; but once it exceeds this amount it will begin to eat into the layer that had been reserved for 1999. If it is large enough it may begin to affect the layers reserved for even earlier years. Thus the effect of using gas now for power generation is to burden future generations with the need to import an equivalent amount of fuel. The value of the gas used at any time can reasonably be regarded as the present worth (at that time) of the cost of importing the equivalent amount of fuel in the first year in which such imports would become necessary as a replacement to natural gas supplies.

The problem therefore is one of defining the real economic cost, as far is it can now be foreseen, of fuel imports towards the end of the century. The main alternative to natural gas as a fuel is likely to be in the future, as it is now, fuel oil, and attention has therefore to be given to the likely international price of fuel oil in the distant future. However there is another dimension to the foreseeable economic cost of large-scale fuel imports in the future—the burden that it will place on Pakistan's foreign exchange budget—and so special consideration must be given to the foreign exchange component of the cost of fuel oil imported and delivered to energy consumers in West Pakistan.

The Economic Price of Fuel Oil

Current fuel oil prices were cited in Table 3A-11, but these prices include substantial tax and foreign exchange components, so that they have to be adjusted before they can be taken as indicating real economic costs. In June 1964 Burmah-Shell quoted a price to S&W for bulk supplies of fuel oil cif Karachi, excluding taxes. This price (about Rs. 57 or $12 per ton of heavy fuel oil) may be taken as 100 percent foreign exchange. The net-of-tax price at which the Pakistan Refinery supplied fuel oil at refinery gate in 1965/66 was almost the same—about Rs. 56 per ton. The foreign exchange component of this price is hard to identify because it was incurred for purchase of crude oil from which many products were derived, so that any distribution of the foreign exchange burden among the different products would be somewhat arbitrary. The net current foreign exchange costs incurred by the refinery for import of oil for processing (i.e., foreign exchange cost of imported crude plus additives less foreign exchange earnings from products exported) was about 70 percent of the total earnings of the refinery from inland sales of petroleum products. On this basis it is possible to say that the foreign exchange portion of the fuel oil price in the short term is about 70 percent or Rs. 40 ($8.40) per ton. However, from a longer term point of view, the foreign exchange cost of domestically refined crude oil is obviously much greater chiefly because of the large foreign exchange component of the capital costs of refineries. Therefore, if it is assumed that substantial future needs of fuel oil could be refined domestically from imported crude,[1] the long-term foreign exchange costs of such supplies might be set at about 85 percent.

The ex-refinery net-of-tax price of Rs. 56 per ton of fuel oil was based on a current price of crude of $11.95 per ton cif Karachi, exclusive of duties, taxes and wharfage, etc. The long-term trend of the price of the crude is quite uncertain; it could be subject to violent fluctuations due to unforeseeable political developments. Over the last 10 years cif crude oil prices have shown a substantial downward trend as a result of both falling freight prices and falling fob crude prices. Part of this sharp fall results from the disturbance in the price trend occasioned by the Suez Crisis of 1956, but even since 1959 oil freight costs on a worldwide weighted average basis have fallen at a rate of about 6 percent per annum while fob prices of oil have fallen at a rate of about 3 percent per annum according to estimates by World Bank commodity specialists. These downward trends are attributable to a number of forces, including restrictive policies on the use and import of petroleum in developed countries, increasing competition with the major producers from independents in the Middle East, Africa and Venezuela, and the expanding volume of Soviet oil exports to the noncommunist world. The Bank's commodity specialists anticipate no reversal of the trend in the near future because these policies are likely to continue, the proven oil reserves of the non-communist world are sufficient to sustain consumption at the 1965 rate for more than 30 years, ultimately recoverable supplies (with account taken of probable and possible reserves and technological advances) could be several times greater, and there have been substantial discoveries of gas in Western Europe recently which could significantly affect demand for oil there. In fact the commodity specialists feel that the propect, at least for the short term, is a further decline in prices of crude oil at a rate somewhat less than that experienced in the past. If an allowance is made for the greater uncertainties of the longer period with which we are concerned, the best oil price figure for long-term planning purposes may be the current one. Nevertheless, in using this, we should bear in mind that political upheavals could increase it substantially at least for short periods.

[1] This assumes that demand for the lighter and medium ends of the crude in West Pakistan would have expanded sufficiently to make it worthwhile to refine the fuel oil in Pakistan. The current position is that demand is peaked in the middle distillates so that some of the heavier products are surplus to domestic requirements and have to be exported at prices that are low compared to world market prices.

If we adopt the rail freight prices provided to the power consultant by the Pakistan Western Railway and assume that they have no foreign exchange component, then we can derive the following set of long-term prices for fuel oil at different foreign exchange rates (Table 3A-12). The first column shows net-of-tax prices for fuel oil in Rs. per ton at the 4 different locations. The middle two columns show the same data in terms of Rs. and US cents per million Btu. All these columns are based on converting foreign exchange components at the current foreign exchange rate. The last two columns present the same prices, again in both Rs. and US cents, with the foreign exchange component doubled. It should be noted that the US currency is used here not for indicating international prices but as a unit of account; therefore the rupee prices convert into dollars in both sets of columns at the current official exchange rate but in the second set of columns all foreign exchange components (whether expressed in US dollars or in Rs.) are simply doubled. The rail freight rates assumed in these calculations, being current financial prices, rather than economic prices (i.e., excluding duties, taxes, etc.), are probably on the high side for use in the calculations at current foreign exchange rates but on the low side for use in the calculations at a higher foreign exchange rate (i.e., its scarcity price).

Economic Price of Natural Gas

Before the prices of fuel oil given in Table 3A-12 become appropriate for use in our procedure for determining the economic price of natural gas a decision has to be made as to the exchange rate at which the foreign exchange components should be converted. Discussion in Supplemental Paper No. I to this report suggests that the present scarcity value of foreign exchange in West Pakistan should be considered to be about twice the current official exchange rate of Rs. 4.76 to the US dollar. According to the evidence presented there the current supply of foreign exchange and the demand for imported goods in the economy as a whole are such that they can only be brought into balance by effective prices for imported goods which are twice what they would be if foreign exchange were freely available at the current exchange rate and expenditure of foreign exchange were not constrained by Government controls and taxes. The evidence is not complete, relating only to the import side of the balance of payments, but it is indicative. For estimating the

TABLE 3A-12
PRICES OF FUEL OIL FOR PLANNING PURPOSES (EXCLUDING TAXES)

	Current Exchange Rate (US $1.00 = Rs. 4.76)			Shadow Exchange Rate (US $1.00 = Rs. 9.52)	
	Rs. per ton[a]	per million Btu		per million Btu	
		Rs.	US cents	Rs.	US cents
Karachi	70.0[b]	1.69	36	2.84	60
Mari	83.0	2.00	42	3.16	66
Multan	113.0	2.72	57	3.88	81
Lyallpur	116.0	2.80	59	3.96	83

[a] Assumes 18,530 Btu's per lb. or 41.5 million Btu's/long ton.
[b] i.e., the base price of Rs. 56/ton plus Rs. 14/ton delivery charge, in Karachi, 85 percent of the Rs. 56/ton is assumed to be foreign exchange cost (see discussion above).

future effective foreign exchange rate it is impossible to go even as far as this. What we require is a detailed analysis of the future demand and supply for foreign exchange to give some indication of the foreign exchange stringency that is likely to exist at different times through the Perspective Plan period and subsequently. What we have is no more than the general judgment that the Perspective Plan certainly implies no easing in the foreign exchange situation and probably indicates some increase in its scarcity.

Within these constraints the best course that seems feasible is to follow through with the assumption that was made in the determination of the current scarcity value of foreign exchange—namely, that the current allocation of available foreign exchange is reasonably optimal. This paper shows above that this allocation involved devoting about three percent of available foreign exchange to purchase of fuel imports. It was further assumed that about 3 percent of the annual supply of foreign exchange could continue to be used for fuel imports without upsetting the optimality of the general allocation of foreign exchange among different sectors. Projections based on this assumption suggested that this would provide barely enough foreign exchange to meet those of West Pakistan's fuel requirements which could not be supplied from domestic sources. This was partial confirmation, from the point of view of the energy sector, of the general statement that the Perspective Plan implies no alleviation of the foreign exchange problem. Nevertheless, within the framework set by these assumptions, it would be possible to import fuel up to the limit of three percent of foreign exchange expenditure at prices calculated on the basis of the current scarcity value of foreign exchange—about US cents 66 per million Btu, for instance, for fuel delivered to Mari, according to Table 3A-12.

Fuel imports required to meet needs that had previously been met by natural gas will clearly be additional to this three percent of foreign exchange expenditure, for the projection in Table 3A-10 of this Paper showed very substantial amounts of total fuel requirements being met by natural gas in later years besides those met by imports within the fixed limit. Clearly then the additional fuel imports occasioned by exhaustion of the natural gas reserves of the Province would exacerbate the general shortage of foreign exchange. The effect of the need for additional fuel imports can be assessed, for purposes of illustration, on the assumption of unity price elasticity of demand for import goods. Suppose that the requirement for imported fuel increases 33 percent from 3 percent of total foreign imports to 4 percent. Then imports demanded at the old foreign exchange price (of double the current rate) would be one percent more than the total foreign exchange available; the scarcity value of foreign exchange would rise one percent and marginal imports in all sectors would be eliminated.

Thus, the result of the greatly increased need for fuel imports would be not only to increase the amount of foreign exchange that must be allocated to cover these imports but, pari passu, to cause an upward shift in the effective exchange rate—indicating the effect of the increased foreign exchange stringency on all foreign-exchange-using sectors. This would be a real cost to these sectors resulting from, and therefore attributable to, the import needs of the energy sector. An indication of the total cost of the additional imports required can be obtained, in the absence of better evidence, by assuming again unity price elasticity of demand for imports. The cost to the other sectors in terms of increased rupee prices of imports would be approximately equal to the value of the additional amount of foreign exchange that had to be allocated to cover the increase in fuel imports. Thus the foreign exchange rate which would appear reasonable for purposes of this analysis, as a means of indicating the burden added by not conserving natural gas reserves, would be twice the current scarcity rate, or, in other words, twice the rate on fuel imports within the 3 percent level. Such a rate, calculated on the basis of many simplifying assumptions, can clearly only be indicative but it seems to encompass reasonably adequately the double penalty that should be attached to additional fuel imports: the direct foreign expenditure, valued at the current scarcity rate of exchange, and in addition the effect on the exchange rate for the whole economy—here valued at an amount equal to the additional direct foreign exchange expenditure involved.

Valuation of the foreign exchange component of fuel imports required to substitute for natural gas at twice the current scarcity price (or four times the current official exchange rate) would mean that fuel delivered to Mari/Sui at the time of exhaustion of gas reserves would cost the Pakistan economy Rs. 5.42 or $1.14 per million Btu. Therefore if a million Btu of gas that would have been available in 2000 is used, say in 1966, for generation of power, this would mean that Pakistan faces an additional cost burden of $1.14 in 2000. The present worth of this cost, on an eight percent discount rate, is US cents 8.1. The real sacrifice to the Pakistan economy involved in using this million Btu of gas in 1966 is therefore Rs. 0.39 or US cents 8.1. Similar calculations can be made for other years. As the cumulative consumption of gas for electricity production increases beyond the projected level of non-electrical consumption in 2000, so layers of gas that had been reserved for earlier years will be affected and the year in which the corresponding fuel import will become necessary will be brought forward. A series of calculations can thus be made, one for each year, which take account of this cumulative reduction in the amount of gas available for nonelectrical purposes and which indicate the real economic value of the gas in each year.

Calculations of this sort cannot however be made without some assumption as to the amount of gas that is required for generation of electricity, for the larger the draft on the gas reserves, the more rapidly will the gas reserves be exhausted and the earlier are the years when conversion to imported fuel oil would become necessary. Many of the programs to be considered in the course of the Study do not in fact differ sufficiently from each other to make separate calculations worthwhile. However, the presence or absence in a program of Tarbela, with its annual output of 12 to 13 billion kwh, obviously makes a tremendous difference. Therefore, separate calculations have been made, on the above lines, as to the economic value of gas in different years, first, on the assumption that Tarbela will come on line in 1975 and second, on the assumption that it will be completed in 1985.

The economic value of gas which results from this approach depends critically on the assumption made with respect to reserves as well as on the assumptions about future price trends for fuel and for foreign exchange. The most uncertain of these is the reserves. It is shown in Supplemental Paper No. 3. Estimates of gas reserves have recently been revised sharply downward. On the assumption that all the known fields with reserves of good quality gas would be brought into use by appropriate siting of plants or by linking them with the existing Sui pipeline so that they would be available to meet projected nonelectrical demands or requirements for power generation, we have adopted a total reserve figure of about 7,300 trillion

Btu (i.e. Sui + Khandkhot + Mazarani + Mari + Sari Sing). However, to indicate the sensitivity of the approach to changes in the estimates of reserves, the calculations have also been run for the hypothetical larger reserves (9,500 trillion Btu).

Table 3A-13 shows the results of these calculations. The consumption of gas for production of electric power would be small in the early part of the period relative to the size of the reserves, and the year of exhaustion of the gas reserves would be some distance into the future, so that the economic value of the gas at well head is low. By 1975 it would be nearly 20 cents per million Btu if gas reserves were as presently estimated (and about 10 cents per million Btu if gas reserves turned out to be at the higher level). In 1978 the economic price trends for the case with Tarbela in 1975 and that with Tarbela in 1985 would start to diverge. If Tarbela is completed in 1975/76 then the economic value of gas in 1980 will be, on present knowledge, somewhat below 30 cents per million Btu.

TABLE 3A-13
ECONOMIC PRICES OF NATURAL GAS ON DIFFERENT ASSUMPTIONS WITH REGARD TO COMPLETION DATE OF TARBELA AND SIZE OF GAS RESERVES
(cents per million Btu)

	Total		Total	
	Gas Reserves: 7,300 trillion Btu		Gas Reserves: 9,500 trillion Btu	
	Tarbela, 1975	Tarbela, 1985	Tarbela, 1975	Tarbela, 1985
1966	8.1	8.1	4.3	4.3
1967	8.8	8.8	4.7	4.7
1968	9.6	9.6	5.1	5.1
1969	10.5	10.5	5.5	5.5
1970	11.3	11.3	5.9	5.9
1971	12.2	12.2	6.4	6.4
1972	13.2	13.2	7.0	7.0
1973	14.3	14.3	7.5	7.5
1974	16.6	16.6	8.8	8.8
1975	18.0	18.0	9.6	9.6
1976	19.4	19.4	10.5	10.5
1977	21.0	21.0	11.3	11.3
1978	22.7	24.5	12.2	13.2
1979	24.5	26.4	13.2	14.3
1980	28.5	30.8	15.4	16.6
1981	30.8	33.3	16.6	18.0
1982	33.3	38.8	18.0	21.0
1983	35.9	42.0	19.4	22.7
1984	38.8	48.9	21.0	26.4
1985	45.3	52.8	24.5	28.5
1986	48.9	61.6	26.4	33.3
1987	52.8	66.5	28.5	35.9
1988	61.6	77.6	33.3	42.0
1989	66.5	83.8	35.9	45.3
1990	77.6	97.7	42.0	52.8
1991	90.5	114.0	48.9	61.6
1992	105.6		57.0	71.8
1993	114.0		66.5	83.8
1994			77.6	97.7
1995			90.5	114.0
1996			114.0	

If Tarbela is not constructed by then, it will be a little above 30 cents per million Btu. By 1985, the economic value of gas will be about 45 cents if Tarbela is available from 1975/76, while it will be more than 50 cents if completion of Tarbela is delayed to 1985. If the gas reserves are as much as 2,200 trillion Btu larger than presently estimated, then the economic values of gas in the different years will be very much less—little more than half the figures given above—so that, for instance, by 1985 the value of gas with Tarbela in 1975 will have risen to only about 25 cents per million Btu and with Tarbela in 1985 it will have risen to about 29 cents per million Btu.

These economic price trends appear reasonable, but they may be on the low side, unless substantial additional discoveries of indigenous thermal fuel are made. It is right that they should be relatively low currently, for the known gas reserves are large compared to existing levels of use. However, the analysis does rest on the assumption that general foreign exchange shortage will not become substantially more acute than it is now until the time that natural gas reserves are exhausted. This is a simplifying assumption, and the more likely path, for the energy sector as for the general economy, is a gradually increasing foreign exchange stringency over the Perspective Plan period. In practice, of course, the price of imported fuel, even when valued at the prevailing scarcity exchange rate, should never reach the levels projected here; but the object of this exercise is not to show actual future scarcity prices of imported fuel but rather hypothetical prices that reflect in the price of fuel the effects on the exchange rate and hence on the overall economy of substantially increased fuel imports.

Using Gas to Earn Foreign Exchange

Another reason why the figures resulting from this analysis should be considered conservatively low estimates of the value of natural gas reserves in the various years, is that there are other uses for gas, not taken into account in the analysis, which could bring forward the critical date when the reserves would be exhausted. The projections of nonelectrical gas requirements used here, although on the optimistic side of the gas transmission companies' sales projections, are apparently more conservative than those used by the Planning Commission. They are also conservative in that they were built up largely in terms of requirements to meet domestic needs; yet there may well be significant possibilities of using gas to produce export products and thus earn foreign exchange. This applies particularly to fertilizer. Some illustrative calculations have been made along these lines regarding the production of nitrogenous fertilizer at Mari/Sui for sale in the neighboring regions of India. Annual demand for fertilizer in the Indian Punjab has been projected to rise, in terms of nitrogen, to about 155,000 tons by 1970. There is at present only one nitrogenous fertilizer factory in Northern India and it has insufficient capacity to meet this demand; but considerable attention is being given to means of increasing the supply of fertilizer. One way of meeting the need that has been discussed is to import ammonia and convert it into urea or another nitrogenous fertilizer locally. 150,000 tons of nitrogen are the equivalent of about 200,000 tons of ammonia. It has been suggested that the cheapest source of ammonia for India would be the Persian Gulf, since an ammonia plant based on natural gas is the cheapest in capital cost and since vast quantities of natural gas are presently being flared in the Middle East oil-producing states. Natural gas for such a plant would probably be available in Kuwait at about US 5 cents per million Btu. But what if an identical plant were established at Mari? Ammonia might then be provided to the Indian Punjab, say Ludhiana, with the following savings in transport cost as listed in Table 3A-14. $20 per long ton of ammonia is probably a conservative estimate of the savings available. However, if we assume that such savings were divided equally between India and Pakistan, then Pakistan would be earning $10 per ton of ammonia supplied to India, over and above the normal profit level of an ammonia plant, thanks to her location and her gas reserves. In other words, if Mari gas were used for this purpose, it would be earning for Pakistan, in addition to the regular profits of an ammonia plant, about US cents 32 per million Btu.[1] A plant to produce 200,000 tons of ammonia per year (approximately 600 tons per day) would need about 10 billion cubic feet of Mari gas per year, excluding power requirements, or 0.16 trillion cubic feet over a 15-year period. This example illustrates what is possible with a relatively small quantity of gas. The potential for absorption of Pakistani ammonia in neighboring areas is obviously a good deal larger than has been indicated in this illustration. High returns are possible when it can be exported—e.g. about 64 cents per million Btu of gas at the current shadow foreign exchange rate used here (i.e. $1.00 = Rs. 9.52). To the extent that substantial quantities of gas could be used, say in the late 1970's for purposes of earning foreign exchange it would considerably increase the economic value of West Pakistan's natural gas reserves.

Financial Price of Gas

In the mid-1960's, the current financial price of Sui gas delivered to the purification plant (which is close to well head) was about US cents 10 per million Btu. SGTC pays a pre-purification price of about 10.8 cents per million Btu (Rs. 0.50

[1] About 37 million Btu of Kuwait gas at US cents 5/million Btu would be needed as feedstock and reformer fuel to produce 1 ton of ammonia. Assuming that Mari gas to the same thermal value would be required, then the earnings attributable to the 37 million Btu of Mari gas would be US$ 10 + (.05 × 37) = $11.85 or US cents 32/million Btu.

TABLE 3A-14
ESTIMATED SAVINGS FROM SUPPLYING LUDHIANA WITH AMMONIA FROM MARI AS COMPARED WITH KUWAIT
(US dollars per long ton)

Sea Transport, Kuwait-Bombay[a]		3
Storage and terminal charges		6
Rail charges[b]		
Bombay-Ludhiana (1,700 km)	IRs 171	
Less: Mari-Ludhiana (700 km)	IRs 87	
	IRs 84	11
		20

[a] A low estimate, based on the figure of $ 6.1/long ton of ammonia for Kuwait-Madras (2,600 nautical miles).

[b] Generous estimates have been made of the route mileage Mari-Ludhiana. The assessment of rail charges is based on the Indian tariff structure which tends to be unduly tapered.

per MMcf) for its gas, while SNGPL pays about 9.6 cents per million Btu (Rs. 0.44 per MMcf) for gas to be purified and dispatched down its line. These prices, which were set by negotiation, are related to factors such as the operating costs of the company exploiting the field (Pakistan Petroleum Ltd.), its sunk costs in facilities and in exploration here and elsewhere, and the extent of the Government's desire at any time to encourage future exploration. Thus they are conceptually quite different from the 'economic values' shown in Table 3A-13. The 'economic value' calculation has little to say about the financial price that should be paid for the gas except that a rising economic value would imply the need for a financial price that would be high enough to encourage careful use of the gas and increased exploration for future reserves. It is the economic value that is more relevant for long-term planning purposes.

Price of Gas Delivered to Market

The 'economic price' figures in Table 3A-13 refer to the value of Pakistan's natural gas reserves in different years at well head. Since the various gas pipelines in the Province are mostly working close to capacity already, increases in supply will require expansion of the gas-transmission facilities, and so the economic price for gas delivered to the market—e.g. to Karachi and Lyallpur—should be somewhat higher. However, the power programs discussed in Volume One vary greatly in the amount of gas required for power generation in the Northern Grid and in Karachi; some require considerable expansion of gas pipeline capacity while others require almost none at all. Therefore use of an average cost per million Btu for transmission of gas from Sui to market would be rather misleading. Since the comparison between gas transmission and electricity transmission is quite important in the

TABLE 3A-15
SUI GAS—PRICE TO KESC
A. Price Structure

	MMcf per Month	Rs. per Mcf
First	10	2.25
Next	90	2.20
	100	2.15
	100	1.95
	100	1.70
All Over	400	1.25
Average for First	400	2.00

B. Actual Prices Paid
(Rs. per Mcf)

Calendar Years	PPL's Price[a] to SGTC	SGTC's Average Price to KGC	KGC's Average Sales Price	KGC's Average Price to KESC
1960	0.50	1.65	2.26	1.97
1961	0.50	1.58	2.23	1.99
1962	0.50	1.49	2.18	1.91
1963	0.50	1.45	2.18	1.85
1964	0.50	1.31	2.12	1.72
1965[b]	0.50	1.28	n.a.	1.66

[a] PPL stands for Pakistan Petroleum Limited, which operates the Sui gas field. [b] Fiscal 1965.

overall study it seemed best from the economic point of view to treat gas transmission explicitly in terms of investment costs for different amounts of pipeline capacity. This is the procedure adopted by the Study Group.

Power Consultant's Gas Price

S&W worked largely in terms of current financial prices for Sui gas, similar to those given in Table 3A-11—about 35 cents per million Btu (Rs. 1.67) for gas delivered to KESC and about 47 cents per million Btu (Rs. 2.25) for gas delivered to WAPDA in Lahore or Multan. These are approximate averages of the prices actually paid. As pointed out early in this annex, both prices are intimately dependent on the individual slab-pricing structures agreed between the utilities and the gas transmission and distribution companies. Reduced requirements for gas may substantially increase the average price to the utilities, while increased requirements would bring down the average price considerably. Appendix Tables 3-1 and 3-2

TABLE 3A-16
SUI GAS—PRICE TO WAPDA FOR NORTHERN GRID
A. Price Structure

Fiscal Years	At Multan Fixed Annual Charges	Commodity Charges	At Lyallpur Fixed Annual Charges	Commodity Charges
	(Rs. '000)	(Rs./Mcf)	(Rs. '000)	(Rs./Mcf)
1965	14,436	1.23	0	1.23
1966	14,436	1.23	4,608	1.23
1967	14,436	1.23	4,608	1.23
1968	14,436	1.23	4,608	1.23
1969	4,560	1.23	3,324	1.23
1970	4,560	1.23	3,324	1.23
1971	4,560	1.23	3,324	1.23
1972	4,560	1.23	3,324	1.23
1973	4,560	1.23	3,324	1.23
1974	4,560	1.23	3,324	1.23
1975	4,560	1.23	3,324	1.23

B. Actual Prices[a]

Fiscal Years	Average Daily Consumption	Total Annual Consumption	Total Paid to SNGPL	Average Price
	(MMcf)	(MMcf)	(Rs. million)	(Rs./Mcf)
1966	36.69	13,396	31.17	2.33
1967	47.18	17,228	37.12	2.15
1968	58.84	21,462	45.89	2.14
1969	58.01	21,170	45.51	2.15
1970	31.90	11,644	22.43	1.93
1971	22.94	8,359	18.34	2.19
1972	20.07	7,337	17.03	2.32
1973	23.07	8,432	18.40	2.18
1974	9.98	3,650	12.44	3.41
1975	5.26	1,935	4.39	2.27

[a] The structure of prices agreed between WAPDA and SNGPL is such that the average price declines rapidly in any one year as consumption increases. The actual price will depend directly, therefore, on the rate at which power load grows and the amount of hydro energy available from existing hydro plants and Mangla. Projections were made three years ago suggesting that the average price to WAPDA for consumption of gas at Lyallpur and Multan would be as set forth over the next decade.

give some details of the current slab-price structures of the historical picture for KESC and the future situation for WAPDA Northern Grid plants as projected some three years ago when the agreement between WAPDA and SNGPL was made.

At the time S&W were preparing their power program, no agreement had been reached as to the price that might be charged for Mari gas. S&W, therefore, had to make some arbitrary choice of price and they selected 12 cents (Rs. 0.57) per million Btu for Mari gas delivered to a power plant in the neighborhood of the field. Of this price, about 2.4 cents were intended to cover the costs of gathering and short delivery. This price is, therefore, approximately the same as the pre-purification price presently charged for Sui gas.

The economic analyses made above also use a single price per million Btu to indicate the value on the field of both Mari and Sui gas, but they suggest that the price appropriate for long-term planning purposes is somewhat higher than that used by the power consultant for Mari gas. The right hand columns of Table 3A-13 indicate the economic value of gas calculated on the basis of approximately the same estimate of gas reserves as was available at the time S&W were carrying out their studies (i.e. Mari with 5 trillion cu. ft. instead of the revised estimate 1.8 trillion cu. ft.). On that assumption with regard to reserves the price used by the power consultant appears appropriate through the major part of the planning period; but it is on the high side for the early part of the period and rather low for the later part. The more recent estimate of the reserves suggests that the scarcity value of the gas should be considered significantly higher throughout the period.

APPENDIX TABLE 3-1

LONG-TERM PROJECTIONS OF NON-ELECTRICAL DEMAND FOR SUI GAS—SNGPL[a]

(MMcf/average day)

		1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Rahimyar Khan:	Other	0.7	0.8	0.9	1.0	1.0	1.1	1.2	1.4	1.5	1.7	1.8	2.0	2.2	2.5	2.6	2.9	3.0	3.3	3.6	3.8
Multan:	Fertilizer	7.2	7.2	7.2	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
	Other	4.7	5.2	5.7	6.2	6.9	7.6	8.4	9.2	10.1	11.1	12.3	13.5	14.8	16.2	17.5	18.7	20.3	21.7	23.3	25.1
Lyallpur:	Other	5.2	5.6	6.2	6.8	7.4	8.2	9.0	9.9	10.9	12.0	13.2	14.6	16.0	17.6	18.9	20.3	21.9	23.5	25.3	27.2
Lahore:	Other	2.6	2.8	3.0	3.3	3.7	4.1	4.5	5.0	5.4	5.9	6.5	7.1	7.8	8.6	9.3	10.0	10.7	11.5	12.4	13.3
Kala Shah Kaku:	Other	2.6	2.8	3.0	3.3	3.7	4.1	4.5	5.0	5.4	5.9	6.5	7.1	7.8	8.6	9.3	10.0	10.7	11.5	12.4	13.3
Gujranwala:	Other						1.8	1.9	2.1	2.3	2.6	2.8	3.0	3.3	3.7	4.0	4.3	4.6	4.9	5.3	5.7
Gharibwal:	Cement	6.4	6.4	6.4	9.6	9.6	9.6	10.3	11.1	11.8	12.6	13.5	14.5	15.5	16.6	17.7	18.9	20.2	21.8	23.2	24.8
Dandot:	Cement	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Rawalpindi/Wah:	Other	3.0	3.2	7.0	7.7	8.5	9.4	10.3	11.4	12.5	13.8	15.0	16.6	18.2	20.0	21.5	23.1	24.9	26.7	28.7	30.9
	Cement	8.8	8.8	12.0	12.0	12.0	18.4	18.4	18.4	19.3	20.7	22.1	23.6	25.2	26.9	29.0	30.9	33.0	35.6	38.5	41.4
Khewra:	Soda Ash	1.6	1.6	1.6	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Sargodha/Bahawal:	Other						0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9
Daudkhel/Kalabagh:	Other						0.5	0.6	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8
	Cement						4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
	Fertilizer						23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2
	Steel						4.8	4.8	4.8	4.8	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Other on Route							1.5	3.9	3.9	3.9	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Kohat:	Cement							2.4	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Peshawar:	Other							11.7	12.3	12.8	19.2	19.6	19.9	20.2	20.6	21.0	21.5	22.0	22.5	23.1	23.7
Total		44.4	46.0	54.6	63.5	66.4	113.2	134.1	142.2	148.6	175.9	183.9	192.7	202.0	212.5	222.2	232.2	243.1	255.0	268.0	281.6
Available from Dhulian		12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Demand for Sui		32.4	34.0	42.6	51.5	54.4	101.2	122.1	130.2	136.6	163.9	171.9	180.7	190.0	200.5	210.2	220.2	231.1	243.0	256.0	269.6
Total Consumption Sui ('000 MMcf)		11.8	12.4	15.5	18.8	19.9	36.9	44.6	47.5	49.9	59.8	62.7	66.0	69.4	73.2	76.7	80.4	84.4	88.7	93.4	98.4

[a] Taken from sales forecast of SMGPL, November 1966, with adjustment to figures for cement in the Gharibwal and Rawalpindi/Wah areas to allow for growth at the rate of 7 percent per year from the early 1970's on and adjustment to the figure for the Daudkhel fertilizer plant to allow for its planned expansion in 1970/71 to 175,000 tons of N per year.

APPENDIX TABLE 3-2
LONG-TERM PROJECTIONS OF NON-ELECTRICAL DEMAND FOR SUI GAS—SGTC[a]
(MMcf/average day)

		1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Karachi:	Cement[b]	9.0	9.0	9.0	9.0	10.9	13.0	12.8	12.8	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
	Other Industries	30.0	31.5	34.1	37.2	42.1	44.9	47.7	50.2	53.0	55.6	58.3	61.0	64.0	67.0	70.0	73.5	77.0	80.5	84.5	88.5
	Commercial	2.0	2.1	2.3	2.5	2.7	2.8	3.0	3.1	3.2	3.4	3.5	3.7	4.0	4.3	4.7	5.0	5.4	5.8	6.2	6.6
	Domestic	1.4	1.7	2.0	2.3	2.5	2.8	3.1	3.4	3.6	3.9	4.2	4.5	4.8	5.2	5.6	6.0	6.4	6.8	7.2	7.6
	Steel Mill[c]						13.0	28.0	29.0	29.0	31.0	33.0	35.0	37.0	40.0	43.0	46.0	49.0	52.0	56.0	60.0
Indus:	Zeal Pak[b]	13.5	13.5	23.2	29.0	29.0															
							31.4	32.1	34.2	36.6	39.3	42.0	45.0	48.3	51.6	55.2	59.1	62.9	67.3	72.3	77.3
	ACC, Rohri[b]	2.4	2.4	2.4	2.4	2.4															
	Other	5.5	6.3	8.8	10.9	12.0	13.2	14.5	15.9	17.5	19.2	21.1	23.5	25.9	28.2	31.0	33.3	35.6	38.5	40.8	43.5
	Total	63.8	66.5	81.8	93.3	101.6	121.1	141.2	148.6	155.5	165.0	174.7	185.3	196.6	208.9	222.1	235.5	248.9	263.5	279.6	296.1
Total Consumption ('000 MMcf)		23.3	24.3	29.9	34.1	37.1	44.2	51.5	54.2	56.8	60.2	63.8	67.6	71.8	76.3	81.1	86.0	90.8	96.2	102.0	108.0

[a] Based on November 1966 sales projections by the Karachi Gas Company and the Indus Gas Company for the period 1967–76; figures for the period 1976–85 have been derived on the assumption that the growth rates of the first decade will be largely sustained.

[b] For the sake of convenience, rather than to represent reality, all growth of the cement industry after 1970 is assumed to take place in the Sind, where gas consumption for manufacture of cement is assumed to increase 7 percent a year.

[c] Including, initially 21.5 MMcf per day generation of electricity in a power plant of 120 mw and 7.4 MMcf per day for other purposes, and increasing from 1975 at about 7 percent per annum.

APPENDIX TABLE 3-3
Long-Term Projection of Fertilizer Production
(thousand tons of N per annum)

	1966	1967	1968	1969	1970	1971	1972	1976	1983
Existing Capacity and Planned Expansion									
Daudkhel: Ammonium Sulphate									
(1 ton $(NH_4)_2SO_4$ = 0.21 ton N)	10.5	10.5	10 5	19.0	19.0	19.0	19.0	19.0	19.0
Multan: Calcium Ammonium Nitrate									
(1 ton NH_4NO_3 $CaCO_3$ = 0.26 ton N)	26.8	26.8	42.4	42.4	42.4	42.4	42.4	42.4	42.4
Urea									
(1 ton CO N_2H_4 = 0.46 ton N)	27.2	27.2	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Planned New Capacity									
Mari-Esso: Urea									
(1 ton CO N_2H_4 = 0.46 ton N)	—	—	40.0	80.0	80.0	80.0	80.0	80.0	80.0
Daudkhel: Ammonium Sulphate Nitrate									
(1 ton $(NH_4)_2SO_4$ NH_4 NO_3 = 0.26 ton N)					78.0	156.0	156.0	156.0	156.0
Additional Capacity Required									
Kandkhot: Urea						92.0	184.0	184.0	184.0
Mari/Sui: Urea								230.0	460.0
Total	64.5	64.5	120.1	175.4	253.4	423.4	515.4	745.4	975.4

PART TWO

Testing Economic Efficiency

Introduction

Efficiency Tests at Various Stages in the Study

Throughout the Study projects and programs have been formulated and evaluated by means of a series of partial analyses representing small steps in the iterative formulation of the Action Program presented in Volume II. Thus, it would be correct to say that tests of economic efficiency penetrated every stage of the Study. Many of these tests were carried out with conventional tools of project evaluation; often safeguarding against the misleading effects of "administered" prices upon efficient resource allocation by substituting approximations to "scarcity" or economic prices into the analysis. Paper 5 which describes the problems encountered in the assessment of the relative merits of diesel versus electric powered tubewells is indicative of the large number of partial analyses which were used to narrow down the wide range of alternative courses of sector development, thus ultimately permitting the application of more comprehensive efficiency tests in the later stages of the Study.

Given the assignment of comprehensive, project-oriented sector planning, and given the consultants' assessment of the resource endowment and implementation capabilities of the sectors under study, it was recognized from the outset that it would also be necessary to employ methods of economic analysis which permit a "broad brush" yet systematic basin-wide evaluation of the most important development alternatives and project opportunities which were being identified by the Study. Given the various forms of interdependence between the large number of investment opportunities which were being identified, it became also increasingly clear that it would not be possible to rely predominantly upon essentially single, isolated project-oriented methodology in such an undertaking since the determination of the optimal investment program required more than the summation of various individual projects which on the basis of isolated evaluations using predominantly market prices had been found to be economically viable.

Comprehensive Efficiency Tests

It was therefore necessary to adopt methods which would allow comprehensive efficiency tests which were able to cope with the essential forms of interdependence between different steps in the development of the system of irrigated agriculture. The Linear Programming Analysis of Potential Irrigation Developments which is presented in Paper 4 describes one of the comprehensive efficiency tests to which the Action Program presented in Vol. II has been subjected by the Study Group. Set up to evaluate in a basin-wide context a large number of alternative irrigation development projects, the analysis strives to maximize the net benefits of outlays for the development of irrigated agriculture giving simultaneously recognition to those overall resource constraints which in the judgment of the Study Group would control strategically the development of this sector. In this manner it was possible to highlight the severity of the respective limiting factors as well as to assess the relative merit of removing one or the other of these constraints. Within the range of the development potentialities identified in the Study it was also possible to identify the requirements of agricultural development programs designed to meet alternative sectoral growth targets. Finally, the shadow prices generated in the context of the linear programming analysis were used to reappraise the relative merits of alternative project possibilities for one and the same sub-section of the Indus Basin, thus making it possible to focus in greater detail upon the impact of scarcity prices upon the processes of project identification and formulation. In a similar manner these scarcity prices were also used to compare alternative programs for surface water storage, and to test specifically whether the investment program formulated around the projected completion of Tarbela Reservoir by 1975 represented the least cost storage program compared to alternative programs involving a deferment of Tarbela.

Data Base of the Comprehensive Efficiency Tests

In the formulation of the linear programming model and in the interpretation of the results of the analysis the Bank Group was continually reminding itself that the results of such an exercise can only be valid to the extent that the model captures the most important development potentialities of West Pakistan's irrigated agriculture and seizes properly on those relationships which control strategically its complex growth processes. Intensive monitoring of the consultant's field work had familiarized the Study Group with a large amount of basic data which had been generated and/or evaluated by the consultants and which could be used to define the cost and benefit dimensions of alternative types of irrigation development projects for the various sub-divisions of the Indus Basin. Thus, on the basis of the consultant's data and technical and agronomic judgment some 500 odd "projects" for the improvement of irrigated agriculture in the Indus Basin were formulated to constitute the basis of the linear programming analysis. Similarly, the constraints upon sector development formalized in the model reflect to a large extent the judgment of the consultants about implementation capabilities in West Pakistan's agricultural sector. Consequently structure and scope of the linear programming analysis were strongly influenced by the type of development strategies which were investigated by the consultants in the course of their basin plan formulation. Furthermore, in view of the timing and experimental nature of the linear programming exercise it was at no time considered justified to request data from the consultants which were not already known to be in existence. This was considered a valid approach in view of the primary purpose of this analysis which was to test the economic efficiency of the action program which emerged from the Study.

Possible Extensions of the Analysis

While the Study Group was satisfied that the model captured adequately the development potentialities identified in the course of the Study, it was nevertheless realized that the model could be made more comprehensive in several ways. Limitations of time and data prevented the exploration of these analytical possibilities, but it will be useful to list a few of the ways in which the Study Group would have liked to extend the scope of its analysis.

For instance, it would have been desirable to expand the number and types of project possibilities considered in the model to include: (a) a wider range of opportunities for foreign exchange saving forms of agricultural development; (b) a wider choice between cropping patterns and thus time patterns of irrigation water demands for each project area so as to capture more fully the determinants of the marginal value of surface water supplies during the period requiring releases from storage reservoirs; (c) alternative levels of net benefits per acre of project area reflecting alternative projections about current input and intensity development so as to highlight the impact of such alternatives upon timing and composition of the public investment program; (d) improvement "projects" for the rainfed areas outside the Indus Basin canal commands which would have allowed the determination of the size of the water investment program in the light of the growth potential and input requirements of the rainfed areas.

While all of these extensions of the analysis would have required the formulation of a wider range of alternative investment and improvement projects, other improvements in the analytical scope and capability of the model could have been obtained by a reformulation of the basic model so as to facilitate the analysis of the impact of variations in such important parameters as the cost of capital, and the projected growth of private groundwater development upon the size and composition of the public investment program.

These possibilities for an expansion of the analytical scope of the linear program have been referred to in order to emphasize at the outset that the results of the comprehensive efficiency test presented below have to be understood with reference to the range of development potentialities and resource limitations considered in the model.

SUPPLEMENTAL PAPER IV

A Linear Programming Analysis of Potential Irrigation Developments

General Description of the Linear Program Employed in the Analysis

Based upon the various investment opportunities identified by the Study Group's consultants in the field of irrigation development, the Study Group constructed a linear programming model for the allocation of water and investment resources. This model is aimed at deriving an optimal pattern of outlays for the development of irrigated agriculture, differentiated by type, regional allocation, and timing of outlay. In the derivation of the optimal pattern of these outlays, this analysis made it possible to give explicit consideration to the most economic use of those resources which may be judged to limit the development of West Pakistan's irrigated agriculture during 1965–85.

The limiting resources singled out in this analysis are: foreign exchange, surface water supplies during months of low river flows, administrative and engineering capability to execute tubewell and canal remodeling projects, and the availability of public development capital.

Thus, formally, the linear programming approach as employed in this analysis may be described as a step-by-step procedure to determine that sequence of investment outlays, or projects, which maximizes the net present worth of the total investment program without exceeding the resource availabilities in the above-mentioned categories.

In the application of the linear programming technique to test the economic efficiency of the project selection made by the Special Study consultants, the Study Group first followed the consultants' judgment about the future availability of limiting resources as closely as possible. In this way it was possible to deduce an indicative list of priority projects comparable to that derived by the Special Study consultants. Next, and more important, the use of the linear programming technique allowed the Study Group to vary the levels of resource availability and thus to test the effects of both an under- or overestimate of the severity of one or several of these constraints upon the size and composition of the proposed investment plans.

The following paragraphs deal in order with: the alternative projects considered in the analysis, the resource limitations imposed upon program formulation, and the criterion employed to choose the optimal investment programs. A technical description of the structure of the linear program is given in Appendix 4-1.

Alternative Projects

Some 500 potential water projects for improving production on irrigated acreage in 54 canal commanded areas of the Indus Basin have been considered in the analysis. All of these potential projects have been defined in a simplified form on the basis of IACA data. To do this, the numerous individual peculiarities relating to each project, e.g., the quality of the soil, depth and distribution of groundwater, specific drainage problems, the prevailing size of farms, the location of the canals, and so on had to be ignored. An individual project appraisal can take these details into account, but a comprehensive, comparative evaluation cannot. For these reasons, the benefits and costs of each project had to be summarized in a handful of numbers which were then compared with other numbers describing other projects in a standardized manner. Consequently, the results of this analysis are suitable only for a preliminary identification of a promising list of investment opportunities. However, in spite of the standardized nature of the "projects" considered in this analysis all of them are consistent with the canal command analysis carried out by the Special Study consultants.[1]

All data which define the projects are based on IACA's cropwater requirements, their estimate of acreage in the CCA, canal size and groundwater quality zones, as well as their estimate of the achievable cropping intensity and yields and the detailed water budgets computed for alternative conditions of development in the reference years 1975, 1985 and 2000. Combining these IACA assumptions and data with various combinations of the characteristic features of the IACA water budgets, the alternative courses of action were formulated. These are described fully in Appendix 4-1.

The alternative courses of action involve essentially: improving the flow-irrigated acreage of each canal command through the construction of tubewells, tile drains, remodeling of canals, through increased supplies of regulated surface water and through combinations of these measures. The decision whether and when to provide what combination of these improvements, i.e. whether and when to implement a specific public project, is viewed as a Government decision.

Limiting Resources

Five categories of limiting resources have been considered in this analysis: (a) foreign exchange, (b) surface water in months of low river flow, (c) capability for implementing public tubewell projects and (d) capability for implementing canal remodeling projects, and (e) public investment funds. In the context of this analysis, a program is called "feasible" if its aggregate requirements do not exceed the available supplies of any of these limited resources. To test the "feasibility" of any given combination of projects, each alternative course of action is defined by "input coefficients" which express the resource requirements of each project per acre covered. The sum of the individual project requirements represents the total resource requirements of the investment program. A brief discussion of the five specific resource limitations follows.

The Foreign Exchange Constraint. It is assumed that some part of the total foreign exchange resources of the economy is to be made available to the agri-

[1] IACA, Report Volume 5, Annexure 7, Chapter 6.

cultural sector to meet its foreign exchange needs for both operating and developmental expenditures, in each year of the program. Two years are singled out as test years: 1975 and 1985. For each of these two years, an estimate was made of the amount of foreign exchange likely to be available to the agricultural sector and the linear program was required to consider only agricultural investment programs whose total foreign exchange requirement in each of these years does not exceed the estimated allotment. As the analysis was formulated, a program was deemed feasible if it lived within its foreign exchange means in the two years 1975 and 1985: no calculations were made for any other years.

The Rabi Surface Water Constraint. The surface water availability during the period November to April has been considered as a separate constraint in the formulation of the feasible investment program. For each mode of development considered, an "input coefficient" for rabi surface water requirements per acre in the test years 1975 and 1985 has been computed. At the same time, the linear program includes an estimate about global surface water availability during the November-April period in the two test years.

The Public Tubewell Implementation Constraint. Explicit restrictions have been placed on the size of the public groundwater development program. These restrictions recognize the fact that shortages of administrative and skilled manpower resources impose an upper limit on the public tubewells that can be brought into operation. Thus, for each project involving public tubewells an "input coefficient" has been formulated which expresses the claim of the particular project upon the scarce tubewell implementation capacity. Again, a check is undertaken to make sure that the public tubewell program can be implemented.

The Canal Remodeling Implementation Constraint. As in the case of the public tubewell program, a restriction has been placed on the size of the canal remodeling program in the two decision periods, which in part reflects the intricate design problems involved and in part the limited administrative and technical resources available for project implementation. For each project involving canal remodeling, an "input coefficient" expresses the project's claim upon the globally limited implementation capacity. Since this limitation is Basinwide, there is nothing to prevent all the permissible canal remodeling from being allocated to a single project area.

The Public Investment Fund Constraint. The overall objectives of the program formulation undertaken by the Special Study consultants do not recognize a budget constraint; in fact, it is argued by IACA that implementation constraints representing sociological and organizational factors will be more decisive determinants of the size of the public investment program than some general limit in the form of development finance.[1]

Without judging the validity of this position, the linear program analysis allows us to gain some insights into the effects of a binding public-investment-fund constraint upon the size and composition of the water investment program. For this purpose, the period 1965 to 1975 was singled out and the linear program is required to consider only agricultural investment programs which in their total claims upon public investment funds do not exceed a certain stipulated level. This constraint was only formulated for the period 1965–75.

[1] IACA, Comprehensive Report, Chapter F, Development Criteria, page 89.

Gross Production Value Targets. In addition to the constraints which reflect estimates of specific resource availabilities, the linear program includes a constraint which was designed to give explicit expression to a desired growth of agricultural output. The agricultural sector is such a central part of Pakistan's economy that its development cannot be considered in isolation from the rest of the economy. Indeed, the perspective planning documents imply a minimum growth rate for the agricultural sector if the requirements for food and for agriculturally based exports are to be met. Thus, the linear program sets lower limits to the gross value of output and of the agricultural sector in each of the two test years. The gross value of output per acre in each of the test years has been estimated for each of the projects and is included as one of the defining coefficients. These per acre output coefficients are utilized by the program in the same way as the input coefficients to assure that the investment program as a whole satisfies the constraints. There are two such output constraints, one for each of the test years.

In the course of the Study Group's analysis, it was found that no feasible program for the development of irrigated agriculture, composed of the projects defined in the linear program, would give enough output response to enable West Pakistan to satisfy the effective demand for agricultural products implicit in the income growth projected by the Perspective Plan. This assessment takes into consideration the output response of nonproject areas. It assumes as given the levels set for the implementation constraint and surface water availabilities (including Tarbela), but to make the case clear it assumes there would be no restrictions on the availability of foreign exchange or public investment funds to the agricultural sector. If the linear program assesses the development potentialities in the Indus Basin correctly, this finding means that unless some of the resource limitations can be relaxed, more modest production goals will have to be accepted.

These results of our analysis have been anticipated in order to point out that the minimum production constraint could not be used without the simultaneous release of other constraints. However, this output constraint has been used to keep track of the effects of changes in some of the resource availabilities upon the attainable growth of agricultural output, as well as in the analysis of the composition of the surface water storage program.

The Optimal Program

Thus far, we have described in general terms the nature of the investment choices considered by the linear program and how it ascertains whether any proposed combination of projects is feasible. A final feature of the analysis compares the desirability of different feasible programs. The method is similar to that used to test whether a program conforms to one of the constraints. Again it should be recalled that the term "program" is used here to refer to a program of investment in some areas as well as, by implication, a decision of inaction with regard to the other areas in the Indus Basin. Thus, in testing the feasibility and desirability of a given program the resource claims, output responses, and net benefit of the project areas are being considered together with the resource claims, output responses and net benefits of the nonproject areas.

To determine the desirability of such a program each mode of cultivation of irrigated acreage, whether it requires Government investment or not, is characterized by a "valuation coefficient." These coefficients are deduced by going through the following steps. First, for each mode of cultivation a projection is made of the time path of cropping intensities and yields per acre for each of the principal crops grown in the region. These time paths of physical outputs are multiplied by constant prices to obtain corresponding time paths of gross values produced per acre. These time paths are then discounted back to 1965, using an 8 percent rate of discount, to obtain an estimate of the present value of the production per acre. Associated costs for farm operations, project operations, investments and maintenance are similarly estimated over the years and discounted back to 1965. Given the net present value coefficients per acre, the linear program calculates the aggregate net present value of all the projects in the program as well as the net present value contributed by the nonproject areas. The sum of these net present values is adopted as the measure of the desirability of an investment program. That is, if there are two feasible programs proposed to the linear program, it will compute the net present value of each of them and will indicate as more desirable the one with the larger net present value. The linear program then reports for each decision period the characteristics of this "optimal" program in terms of the type of project proposed in each of the 54 canal commands and the number of acres proposed to be covered by that project.

It should be stressed again that the regional allocation of projects and their proposed timing should be considered as purely indicative. However, the results of the analysis should be considered as suggesting development potentialities which, given the particular resource shortages specified in the linear program, merit more detailed consideration.

It should also be stressed that the formulation of the linear program described above was strongly influenced by our knowledge about the data which had been generated by IACA in the course of *their* Basin plan formulation. Given the timing and the experimental nature of the Study Group's linear programming analysis, it was at no time considered justified to request data from IACA which were not already known to be in existence. Furthermore, broad adherence to IACA data and basic approach was mandatory if the linear program was to fulfill its operational function in the Study. These operational limitations should be recalled when the linear program is judged in its structure and adequacy.

Results of the Linear Programming Analysis

The formal programming analysis described above relies upon the general assumption that the improvement of say 2,000 acres will cost twice as much as the improvement of 1,000 acres and will yield twice as much output, i.e., in general it is assumed that both the costs and the benefits of a given development project will be approximately proportional to the number of acres developed. By virtue of this assumption, the problem of finding the optimal investment program subject to the limited availability of certain resources becomes a linear programming problem for which solution techniques utilizing electronic computers are readily available. The results set out below were obtained with the help of an IBM 7090 computer. For this program, it was necessary to prepare over 4,000 input data that in summary form describe the alternative modes of cultivation considered by the analysis. This work was carried out with the help of the Programming Section of the World Bank's Statistics Division.

Before presenting the results, it should be stressed that the findings of this analysis have to be understood and interpreted with reference to the logic of the model by which they were obtained. The results are only valid to the extent that the model seizes properly on those relationships which control strategically the phenomenon of economic growth in West Pakistan's irrigated agriculture. In particular, the valuation of limited resources should be considered in the light of the alternative modes of production considered in the model. As with any other analysis, the results can be no better than the data and assumptions used in it.

The Optimal Investment Program Assuming IACA's Public Tubewell and Canal Remodeling Constraints

Guided by the judgment of IACA on resource limitations, the starting point of the analysis was the search for that investment program which, formulated within these limitations, would generate the highest present worth of net benefits. For the purpose of this analysis, the resource limitations have been set at the following levels:

Public tubewell implementation capacity
- during the period 1965–75: 20,000 four-cfs wells
- during the period 1975–85: 30,000 four-cfs wells

Canal remodeling implementation capacity
- during the period 1965–75: one MA
- during the period 1975–85: five MA

It has also been assumed that rabi surface water availability during the months November-April, up to and including 1975, would comprise unregulated river flows in the Indus, Kabul, Chenab and Jhelum plus the releases from Mangla and Chasma during the November-April period. Rabi surface-water availability for the period 1976–85 during the months November-April was assumed to comprise the unregulated river flows in the Indus, Kabul, Chenab and Jhelum plus the releases from Mangla, Chasma and Tarbela during the November-April period. In addition releases from the Sehwan-Manchar storage project have been included beginning 1980/81.[1]

The optimal investment program subject to these constraints would generate in the Indus Basin a gross value of agricultural output of Rs. 10.5 billion and Rs. 19.4 billion in 1975 and 1985 respectively. Starting with a base year production of Rs. 6.77 billion this implies an average annual growth rate of gross production value in the Indus Basin of 4.5 percent and 6.4 percent over 1966–75 and 1975–85, respectively.

This projection of the attainable production response employs the cropping pattern and the acceptance rates and output responses to agricultural inputs other than water as set forth by the Bank's consultants in their work as reported in Volume Two.

The resulting list of priority projects for 1965–75 is given in Table 4-1. An additional priority area not listed in the table is Dadu South, where during the period 1970–75 the program indicates priority for providing horizontal drainage combined with canal remodeling and with the development of the limited area en-

[1] See Appendix 7 for detail.

dowed with usable groundwater some other commands would be included but for technical reasons. For instance, the preliminary data describing the cost and benefits of public tubewell development in the Peshawar commands and Paharpur command would give these areas high priority for early public tubewell development. However, data uncertainties regarding aquifer conditions and expected difficulties in well drilling led the consultants to exclude the Peshawar commands from their recommended tubewell program for 1965–75. The Study Group's economic analy-

TABLE 4–1

PRIORITY AREAS FOR PUBLIC TUBEWELL DEVELOPMENT WITHIN A PUBLIC TUBEWELL PROGRAM COMPRISING THE INSTALLATION OF 20,000 WELLS DURING THE PERIOD 1965–75[a]

New Projects	Covered CCA (million acres)	No. of four CFs Wells Required by Project
New Projects		
Dipalpur above BS Link	0.372	625
Ravi Syphon-Dipalpur Link	0.595	797[b]
Bahawal above MB Link and Qaim	0.093	180
Fordwah and Eastern Sadiqia II	0.297	550
Pakpattan above SM Link II, Mailsi above SM Link	0.347	677
Lower Chenab I (excluding SCARP 1)	1.753	1,790[c]
Bahawal below MB Link, I	0.165	220
Bahawal below MB Link, II	0.264	130[d]
Sidhnai II	0.248	18[e]
Haveli I and II	0.106	184
Abbasia Panjnad II	0.942	1,582[f]
D. G. Khan	0.647	1,273
Thal	1.360	1,871
Rohri North	0.598	1,043
Rohri South	0.528	886
Dadu South Drainage-cum-Canal Remodeling Project	0.027	93[g]
	8.342	11,919 wells
Ongoing Projects		
SCARP II	1.551	2,850[h]
SCARP III	0.934	1,473
SCARP IV	1.698[i]	3,274
Khairpur West	0.252	484[j]
	4.435 MA	8,081
	12.777 MA	20,000

[a] The two drainage cum canal remodeling pilot projects recommended by IACA for Rechna and Bari Doab are not considered in this analysis.

[b] Combined with canal remodeling to serve: 0.338 MA.

[c] Combined with canal remodeling to serve: 1.035 MA; 91 percent of the required canal remodeling to be undertaken during the period 1975–85.

[d] Represents 28 percent of the tubewell capacity required by project, remainder to be installed after 1975.

[e] Represents 4 percent of the tubewell capacity required by project, remainder to be installed after 1975.

[f] Combined with canal remodeling to serve 0.160 MA.

[g] Combined with canal remodeling to serve 0.276 MA.

[h] 206 wells installed in anticipation of pumping requirements created by canal remodeling which is recommended for the period after 1975.

[i] Includes deferred SCARP II—Area.

[j] Four cfs equivalent wells.

sis followed the consultants' judgment on these points and extended it to Paharpur Command as well. However, high priority should be given to the study of these commands as very promising potential project areas. In addition to the listed public action program, it was assumed that the projected growth in agricultural output during the 1965–75 period would be supported by the installation of approximately 19,500 new private wells during the period.

For the 1975–85 period the investment program indicated would comprise the priority tubewell projects listed in Table 4-2. Public development of usable groundwater previously left to private exploitation, combined with the provision of vertical drainage in waterlogged areas endowed with saline groundwater. In addition the program for 1975–85 includes:

1. Installation of drainage wells in commands where the usable groundwater was developed in the preceding period involving a total of 2,000 wells.
2. Completion of the Sidhnai II Tubewell Project and the Bahawal Project involving the installation of 837 wells and completion of the remodeling project in Lower Chenab I.
3. Canal remodeling as a follow-up to previous public development of the usable groundwater in Lower Jhelum I.
4. Canal remodeling cum drainage projects for Fordwah and East Sadiqia I, Panjnad Abbasia I, Northwest saline groundwater, Khairpur East and Gaja-Tando Bago.
5. Canal remodeling for the following rice areas: Begari Sind, saline groundwater, Desert including Pat; Northwest Khirtar; and Rice.

Regarding the priorities for public tubewell development prior to 1975, the analysis confirms the priority of the following projects included in the revised IACA program:

Dipalpur above BS Project
Ravi Syphon-Dipalpur Link Project including canal remodeling
Bahawal Qaim Project
Fordwah Sadiqia Project
Lower Rechna Development Area
Sidhnai II Project
Panjnad Abbasia Project including canal remodeling
Shorkot-Kamalia Project
Thal Command
Rohri North Project
Rohri South Project

With regard to two of those projects, Bahawal-Qaim and Sidhnai II, the economic analysis confirms only the partial inclusion of these projects in the 1965–75 tubewell program.

The analysis does not confirm the IACA priorities for public tubewell development prior to 1975 for the following projects:

Dipalpur below BS Project
Begari Sind Project
Sukkur Right Bank Project

TABLE 4-2
PROJECTS WITH PRIORITY FOR THE PERIOD 1975-85

	No. of four-cfs wells required by project
Fordwah and E. Sadiqia I	98
Pakpattan above SM Link I	1,044
Dipalpur below BA BS Link	807
Lower Bari Doab	2,712
Mailsi below SM	765
Sidhnai I	725
Abbasia Panjnad I	287
Paharpur	210
Upper Swat	318
Lower Swat	250
Kabul River	180
Warsak High Level	214
Begari Sind, usable groundwater	768
Northwest, usable groundwater	309
Dadu North	367
	9,054 wells

Nor does it confirm the priority for starting a public tubewell project in Lower Bari Doab Command before 1975.

Finally, this analysis recommends the completion of a public tubewell project in Pakpattan above SM II Command before 1975 while the revised IACA program recommends public tubewell coverage for this Command after 1975. The early priority derived for Pakpattan above SM II reflects the fact that public tubewell coverage in this project allows for permanent surface water substitution at a time of serious rabi surface water shortages—and in this analysis the rabi surface water savings were assigned imputed benefits.

This exercise indicated that the project priorities were influenced by the assumptions about a tubewell project's ability to bring about substitution of groundwater for surface water use. Since the speedy adoption of a mode of project and systems operation which would allow for the realization of these additional benefits is somewhat in doubt, the analysis was repeated subject to the assumption that projects initiated after 1969 will not realize benefits from surface water substitution prior to 1975. The general result of this change in assumptions is a fivefold increase in the scarcity value of rabi surface water in the period prior to 1975. As a result of this change in the imputed value of rabi surface water used by the various projects, the comparative advantage of early public groundwater development in a number of presently nonperennial areas is sufficiently reduced to make postponement of public groundwater development economically advantageous. This is the case with regard to Dipalpur above BS Link Project, Fordwah Sadiqia Project and with regard to the development of the usable groundwater zone in D. G. Khan Command. The number of public tubewells set free by the postponement of public development in these project areas would, according to this analysis, best be used in the early implementation of a public groundwater development project in the usable groundwater zones of the Sukkur Right Bank Commands, Ghotki Command and Begari Sind Command. It should be noted that according to this analysis the relative priority for early public groundwater development in the usable groundwater zone of the Lower Chenab Development Area (part of the SCARP V project area) is not dependent upon the early realization of benefits from surface water substitution.

The projects not confirmed deserve further comment. Regarding the Sukkur Right Bank Project the analysis of sensitivity of the established project priorities to the size of the public tubewell program shows that this project represents a "borderline" case within the context of a public tubewell program limited to 20,000 wells. With regard to Dipalpur below BS, IACA concluded in its Project Report that, considering the differential foreign exchange and public sector finance requirements of the public and private modes of groundwater development, the public tubewell project could be deferred until after 1975. To demonstrate the reasons for the different findings of this analysis about the priorities of these projects, separate project evaluations for Dipalpur below BS and Begari Sind are included in a later section of this Paper (pages 189-193).

As regards the allocation of the limited canal remodeling capacity during the period 1965–75, the linear program indicated priority for early canal remodeling in Ravi Syphon-Dipalpur Link Command, Abbasia Panjnad II Command, Dadu South Command and in Lower Chenab I. In the latter Command, the canal remodeling project is scheduled to begin before 1975 but will extend its claims on scarce remodeling capacity into the 1975–85 period.

With regard to the SCARP II area, the linear program confirms the recommendation of the Government of Pakistan that the tubewell development in Lower Jhelum I be supplemented by canal remodeling. The analysis indicates priority for such remodeling in the 1975-85 period.

Further, this analysis confirms the priorities established by IACA for Ravi Syphon Dipalpur Link Command and Abbasia Panjnad Command. However, the analysis does not confirm the IACA priority for early implementation of canal remodeling-cum-tubewell projects in the Khairpur commands. The explanation for this difference in priorities may be found in the assumption made in IACA's determination of water development priorities that, in the absence of project coverage, areas with problems of waterlogging and salinity will experience no improvements in yields over the 1965 levels. This assumption is in its stringency at variance with the approach employed in the IACA project evaluations as well as in IACA's approach to yield projections.[1] To the extent that this stringent assumption was employed in IACA's priority determination of drainage-cum-canal remodeling projects, it tended to raise the incremental benefits attainable through project coverage over and above those which have been projected in the Study Group's economic analysis which employs IACA's alternative approach to the projection of yield developments under conditions of waterlogging and salinity. Since both Khairpur commands are severely waterlogged, the difference in the approach to the projection of yield growth in the absence of project coverage would tend to explain the difference in priorities.

Analysis of the Effects of Changes in the Size of the Public Tubewell Program During the Period 1965–75 Upon Project Priorities

This part of the analysis attempts to ascertain the sensitivity of the established project priorities to changes in the size of the public tubewell program which in the

[1] Volume Two, Annex 10.

IACA program has been limited to the installation of 20,000 four-cfs wells during the period 1965–75. Given the difficulty of making a judgment about Pakistan's implementation capacity regarding public tubewells, this programming exercise allows us to trace the effects of both an over- or underestimate of this particular implementation constraint upon investment plans.

Altering the tubewell constraint, we find that a reduction in the size of the tubewell program by 2,000 four-cfs wells could be minimized in its effects upon the growth of agricultural output by completely postponing the public tubewell projects scheduled in Sidhnai II, by a further postponement of the tubewell project in the Bahawal commands, and by a partial postponement of the projects in Fordwah Sadiqia II and Rohri South. A further reduction of the tubewell program to 16,500 wells could be minimized in its effects upon agricultural growth by a complete postponement of the Bahawal Project, the Rohri South Project and the Fordwah and Eastern Sadiqia Project until after 1975, as well as a partial postponement of the tubewell project in D. G. Khan and the tubewell-cum-canal-remodeling project in the Lower Chenab Development Area.

According to the analysis an increase in the size of the tubewell program should best be used to include the complete tubewell investment requirements of the Sidhnai II and the Bahawal Project in the 1965–75 tubewell program and to advance the tubewell construction in the Sukkur Right Bank Project (beginning with Dadu North).

The Impact of a Binding Public Investment Fund Constraint Upon Investment Plans

Until now, the shortage of development capital has only been considered in the evaluation of investment decisions in the form of an 8 percent discount rate which is held to be an appropriate measure of the marginal return to the economy from alternative uses of funds in appropriate fields. This discount factor is applied to all expenditure streams whether they represent the expenditure of private or public funds. However, it has been argued that, in the evaluation of investment decisions, and especially in the field of public groundwater development, account should be taken of imperfections of the capital market, which make the return to private capital expenditures in alternative uses considerably less than the opportunity cost of public development capital. Only if this fact is recognized, this argument continues, can the evaluation of private versus public groundwater development be sure to yield an optimal allocation of scarce resources.

While it would not be advantageous to review alternative investment opportunities on the basis of different opportunity costs for private and public capital, it would seem to be appropriate to analyze the sensitivity of investment decisions to such divergent opportunity costs via the explicit recognition of a binding constraint on public development funds. Within the framework of the linear program, this approach traces the impact of varying sizes of public water investment budgets upon the composition of the total water investment program, both public and private. A reduction in the availability of public investment funds will increase the scarcity value of public investment expenditures and thus will affect the comparative advantage of private versus public groundwater development. It is therefore possible to assess the sensitivity of public tubewell project priorities to the economic cost of public capital, given different levels of investment fund allocations to water development. Formally, this analysis focuses upon the public expenditure component of the various investment opportunities considered in the linear program. In the case of private groundwater development "projects" only the average cost of the electric distribution lines per newly electrified private tubewell of Rs. 10,000 has been considered. In the case of public tubewell projects, the total public investment outlay has been considered to be Rs. 125,000, including Rs. 35,000 which represents the average cost of electric distribution per four-cfs well. Finally, the full capital cost of canal remodeling has been considered.

On the basis of the shadow prices computed by the linear program on the public investment fund constraint it is possible to derive a benefit/cost ratio for the marginal public investment outlay within the context of public water investment budgets of different sizes. These benefit/cost ratios are shown in Table 4-3. The analysis shows that the returns to public water investment are such that a 5 percent reduction in the public water investment budget raises the benefit/cost ratio on the marginal outlay within this reduced budget to over 3:1, or considerably above the 8 percent level which had been considered to represent the return to the economy from alternative uses of funds in other sectors. According to the linear program, the effects of the successive reduction in the size of the public water investment budget would best be minimized if first, the canal remodeling projects, with the exception of the Ravi Syphon-Dipalpur Link Project, and next, the tubewell projects for the Bahawal Command, were postponed. Should the cut in the water investment budget for the period 1965–75 reach the 20 percent level, the public groundwater development in the Lower Chenab development area (SCARP V) should be postponed as well.

The analysis of the impact of a public-investment-fund constraint upon water investment decisions allows the following conclusions: given the high returns to public investment in groundwater development even when full account is taken of the displaced private investment and of the scarcity of public development funds, the public budget allocations to groundwater development should be upheld unless it can be established that cutbacks in allocations to other sectors would require foregoing investment opportunities which in their payoff match those attainable in public groundwater development.[1]

[1] This conclusion, as any other reached in this analysis, depends of course upon the correct assessment of the comparative and absolute advantage of private versus public groundwater development by the Special Study consultants.

TABLE 4-3
THE BENEFIT/COST RATIO OF MARGINAL PUBLIC OUTLAYS ON WATER DEVELOPMENT DURING 1965–75 AS RELATED TO THE SIZE OF THE WATER INVESTMENT BUDGET [a]

Percentage Reduction in the Optimal Size as of the Water Investment Budget [a]	Benefit/Cost Ratio of the Marginal Public Investment Outlay
0	1:1
5.2	3.4:1
10.2	4.8:1
19.4	4.9:1
25.1	5.0:1

[a] Rs. 2.8 billion during the period 1965–75.

Analysis of the Foreign Exchange Requirements of the Development Program for Irrigated Agriculture

The discussion so far has disregarded problems of foreign exchange availability to the agricultural sector. In fact, the investment program formulated and discussed above allowed unconstrained use of foreign exchange at the official exchange rate. Under these conditions the above-described investment program requires annual foreign exchange expenditures of $71 million and $114 million, respectively for the reference years 1975 and 1985. The distribution of these projected import requirements over the various development activities is described in Table 4-4.

These projections assume that self-sufficiency in fertilizer will be attained around 1970 and that the process of import substitution will continue. Specifically, the foreign exchange components given in Table 4-5 have been assumed for the purpose of this analysis.

It should also be noted that the projected foreign exchange requirements exclude the foreign exchange component of construction costs related to surface-water storage as well as the foreign exchange outlay related to surface runoff drainage in the Punjab and major outfall drains in the Sind.

In the absence of any guidance from official planning documents about planned future foreign exchange availability to the agricultural and water sector, it is not possible to make any assessment of the feasibility of allocating the scarce foreign exchange for the projected uses in the agricultural sector. It is possible to say only that the projected import requirements of the development program covered by this analysis would claim about 5-6 percent of the total annual import bill projected in the Perspective Plan for the reference years 1975 and 1985.

TABLE 4-4
DISTRIBUTION OF PROJECTED IMPORT REQUIREMENTS BY DEVELOPMENT ACTIVITIES

	Reference Year			
	1975		1985	
	Annual F. Ex. Exp. ($ mill.)	% of Total	Annual F. Ex. Exp. ($ mill.)	% of Total
Farm Imports:				
Pest and disease control[a]	6.4	9	10.3	9
Capital Exp. on mechanization and implements[b]	7.1	10	18.2	16
Fuel and lubricants related to mechanized farming	13.5	19	47.9	42
Sub-Total	27.0	38	76.4	67
Water Development:				
Public tubewell development	27.0	38	16.0	14
Private tubewell development	12.7	18	—	—
Canal remodeling	4.3	6	18.2	16
Drainage	—	—	3.4	3
Sub-Total	44.0	62	37.6	33
Total	71.0	100	114.0	100

[a] Estimated imports in 1964/65: $2.2 million.
[b] Estimated imports in 1964/65: $3.0 million.

TABLE 4-5
DIRECT FOREIGN EXCHANGE REQUIREMENT AS A PERCENTAGE OF DEVELOPMENT EXPENDITURES

Type of Expenditure	Foreign Exchange Component (percent)		
	1965	1975	1985
Pest and disease control:	100	55	35
Capital expenditure on mechanization and implements	90	60	50
Fuel and lubricants	100	100	100
Public tubewells:			
Capital cost	60	60	40
Other cost	33	33	33
Private tubewells:[a]			
Capital cost	20	20	20
Other cost	37	37	22
Canal remodeling	65	60	50
Tile drainage:			
Capital cost	40	40	20
O & M cost	50	40	30
Vertical drainage:			
Capital cost	65	60	50
O & M cost	40	35	30

[a] Assumes the following combination of diesel wells and electric wells: 1965–75: 50% diesel, 50% electric. 1975–85: 25% diesel, 75% electric.

However, accepting the statement made in the Government of Pakistan Third Plan document that, for purposes of project appraisals, a scarcity price of foreign exchange should be used so as to reflect properly the scarcity of foreign exchange to the economy,[1] it would be valid to evaluate the size of the foreign exchange allocation to irrigated agriculture in terms of a comparison between the marginal value of a unit of foreign exchange to irrigated agriculture and to the economy as a whole.

From the analysis we find that reductions in the foreign exchange availability to irrigated agriculture during the period 1965–75 yield the following scarcity values of foreign exchange in agriculture as set forth in Table 4-6. Putting it differently, if foreign exchange funds were allocated between sectors of the economy on a basis of competitive bidding, the sector of irrigated agriculture would be able to compete for an increase of its annual allocation from say $63 million to $65 million by offering to pay Rs. 12.63 to Rs. 9.64 for each additional dollar allocated to this sector. At the same time, if the limited foreign exchange availability prior to 1975 cannot be compensated for by increased use of foreign exchange after 1975, the value of foreign exchange allocated to agriculture during the 1975–85 period is increased and the sector could in 1985 afford to pay a higher price for any additional foreign exchange as a direct consequence of the stringency of foreign exchange allocation in the period before 1975.

Following the same approach, we find that a reduction of the foreign exchange availability in the reference year 1985 from $114 million to $109 million would raise the scarcity value of $1 in the agricultural sector from Rs. 4.76 to Rs. 10.

[1] Government of Pakistan, The Third Five Year Plan (1965-70) June 1965, p. 35.

TABLE 4–6
MARGINAL VALUE OF FOREIGN EXCHANGE TO IRRIGATED AGRICULTURE IN 1975[a]

1975 Foreign Exchange Availability ($ Million)	Implied Rupee Value of $1 US in 1975	1984 Foreign Exchange Availability ($ Million)	Implied Rupee Value of $1 US in 1985
71	4.76	114	4.76
68	4.80	114	n.a.
66	8.42	114	n.a.
65	9.64	114	9.28
63	12.63	114	n.a.
59	38.00	114	n.a.

[a] Other constraints set at the levels discussed above.

A further reduction to an annual availability of $103 million in 1985 would raise the marginal value of $1 to agriculture to Rs. 25.

In the interpretation and use of these accounting prices for foreign exchange, it should be kept in mind that, in the analysis which generated these shadow prices, the foreign-exchange-using inputs of any given project or alternative course of action cannot be altered directly; they can be altered only indirectly by means of choosing a different type of project or course of action which has been defined for the respective unit of the canal-commanded acreage. Due to the nature of IACA's studies, no "activities" aiming explicitly at foreign-exchange-saving forms of agricultural development could be included in the linear program formulation. However, with regard to groundwater development, private tubewell development represents a foreign-exchange-saving alternative to public tubewell development. The analysis shows that reductions in the availability of foreign exchange to the agricultural sector lead to changes in public tubewell project priorities in such a way as to favor private development of groundwater in areas for which active private groundwater development has been projected by IACA. The analysis indicates that, given a shortage of foreign exchange which raises the cost of foreign exchange to the economy to a level above Rs. 10 to the dollar, the public tubewell projects for example in Bahawal and Rohri South should be postponed.

Results of Analysis Employing Alternative Output Responses per Cropped Acre

To test the sensitivity of the formulated investment program to alternative assumptions about the output response per cropped acre attainable by 1975, the linear program analysis was repeated for an alternative set of data inputs describing the attainable time path of net benefits per cropped acre.

These alternative projections of output responses assume that during the period 1965–75, the acreage covered by public tubewell projects will attain a growth of GPV per cropped acre of 4 percent per annum. For the period 1975–85 the increase in GPV per cropped acre was projected to be the same as that projected by the Special Study consultants for the same period.

It was further assumed that the productivity increases attainable with present irrigation supplies (historic supplies) in combination with improved agricultural inputs would average 2 percent per annum during the period 1965–75. This productivity growth was applied to the 1965 GPV/per acre of CCA. To give recognition to the fact that the presently insufficient irrigation supplies will eventually seriously impede the further acceptance and application of yield-increasing inputs, the growth of productivity attainable on uncovered acreage has been projected to slow down to an average rate of 1 percent per annum beginning 1975.

In areas endowed with usable groundwater, private tubewell development is assumed to take place at the rate projected by the Special Study consultants. Assuming that one private well of about one-cfs capacity is able to serve 80 acres of CCA, the acreage benefiting from private well supplies is projected to attain a cropping intensity of 150 percent. This privately "covered" cropped acreage is projected to be cultivated as intensely as acreage covered by a public tubewell project, which means that the application of yield increasing inputs and full irrigation supplies is projected to yield up to 1975 average productivity increases of 4 percent per annum over the 1965 GPV per privately covered cropped acre. After 1975, the acreage covered by private tubewell development, still assuming that one private one-cfs well will cover 80 acres of CCA, is projected to attain the same productivity growth as is projected to be attained on acreage covered by a public tubewell field.

The major difference between these alternative output response projections and those employed in the main part of this linear programming analysis is that they project a higher output response per acre of CCA benefiting from private groundwater development. These alternative output response projections may therefore be said to reflect the position taken by many observers of recent agricultural development in West Pakistan which holds that the spontaneous action by the more progressive farmers in adopting new technologies, i.e., small one-cfs tubewells, can set into motion a cumulative process which carries in it the potential for a sustained take-off into rapid agricultural growth. It is argued that these farmers who have made the investment in private tubewells will show the same entrepreneurial initiative with regard to the application of other inputs which also involve a break with traditional practices.

The following discussion presents the results of an analysis which employs projections of output responses which imply a different comparative advantage of private versus public groundwater development. This analysis employs the constraint levels described above.

The optimal investment program subject to these constraints would generate a gross value of agricultural output of Rs. 11.3 billion and Rs. 19.4 billion in 1975 and 1985, respectively. Starting from a base year production of Rs. 6.77 billion, this implies an average annual growth rate of gross production value in the Indus Basin of 5.3 percent and 5.6 percent over the period 1965–75 and 1975–85, respectively. The regional allocation of the scarce resources which generate these aggregate values is described in Table 4-7.

In addition to these priority projects, the program recommends a tubewell project in Ghotki command and in Fordwah and East Sadiqia, and canal remodeling in Lower Jhelum I Command. In these cases the project extends in its resource claims into the 1975–85 period so that only a part of the scarce wells and the scarce remodeling capacity is withdrawn from the overall availabilities set for the period 1965–75. The aggregate production response would also be supported by the installation of approximately 24,000 new private wells between 1965 and 1975. This

TABLE 4-7
PRIORITY AREAS FOR PUBLIC TUBEWELL DEVELOPMENT ASSUMING 20,000 PUBLIC TUBEWELLS ARE INSTALLED DURING THE PERIOD 1965–75[a]

A. New Project

	Covered CCA (million acres)	Four cfs Wells to be Installed
		(no.)
Pakpattan above SM II, Mailsi above SM Link	0.347	677
Lower Chenab I (excluding SCARP I)	1.753	1,788[b]
Haveli I and II	0.103	184
Abbasia Panjnad I	0.513	287[c]
Abbasia Panjnad II	0.942	1,583[d]
D. G. Khan	0.647	1,273
Thal	1.360	1,871
Begari Sind Usable groundwater	0.349	768
Northwest Usable groundwater	0.155	308
Rohri North	0.598	1,043
Rohri South	0.528	885
	7.295	10,667

B. Ongoing Projects

SCARP II:	3,021 wells, of which 376 wells installed in anticipation of requirements following canal remodeling
SCARP III:	1,473 wells
SCARP IV:	3,274 wells
Khairpur West:	484 wells (4 cfs equivalent wells)

[a] The two drainage cum canal remodeling pilot projects recommended by IACA for Rechna and Bari Doab are not considered in this analysis.

[b] Followed by canal remodeling during the 1975–85 period to serve 1.035 MA.

[c] Combined with canal remodeling to serve: 0.475 MA.

[d] Combined with canal remodeling to serve: 0.160 MA.

would bring the total private pumping capacity projected to be in existence by 1975, in the context of this alternative water investment program, to about 37,000.

The above project priorities were determined in the context of a public tubewell program limited to the installation of 20,000 four cfs wells during the period 1965–75. If we alter the tubewell constraint, we find that a reduction in the size of the tubewell program by 1,200 four-cfs wells could be minimized in its effects upon the growth of agricultural output by partly or completely postponing the public tubewell projects scheduled in Fordwah and East Sadiqia II, Pakpattan above SM II and Ghotki. A further reduction of the tubewell program by 1,400 wells could be minimized in its effects upon agricultural growth by postponing the tubewell projects scheduled for Begari Sind (usable groundwater) and Northwest (usable groundwater) until after 1975, as well as a slight postponement of the tubewell-cum-canal-remodeling project in the Lower Chenab development area. Finally, a cutback of the tubewell program from 20,000 wells to 15,000 wells would, in addition to the above adjustments, lead to a postponement of the public project in the Lower Chenab development area beyond 1975 and a postponement of the project start in D.G. Khan so that only part of the project's claim upon scarce resources falls into the 1965–75 period.

According to the analysis, an increase in the size of the tubewell program by 2,600 four-cfs wells should best be used to include the following projects in the priority list:

Dipalpur above BS Link
Ravi Syphon-Dipalpur Link
Bahawal below MB I
Dadu North

The project scheduled for Ghotki should be moved completely into the 1965–75 period and the Fordwah and East Sadiqia II project should be moved up in time.

In the aggregate, a reduction in the size of the public tubewell program for the period 1965–75, all other resource limitations remaining equal, would reduce the first period growth rate of agricultural production. However, a reduced rate of public tubewell installation would be partly compensated for by the installation of a larger number of private tubewells. As far as public groundwater development is concerned, a reduction in the size of the public program during the period 1965–75 is compensated for in the investment plans formulated by the linear program by the installation of a larger number of public wells in the subsequent period.

These aggregate effects of changes in the size of the public tubewell program during the period 1965–75 are summarized in Table 4-8. As these results show the alternative approach to the projection of productivity growth attainable without public water investment has important consequences for the comparative advantages of private development of fresh groundwater (less than 1000 ppm TDS) versus public development of the usable aquifer (0-3000 ppm TDS). Acceptance of the alternative output responses employed in this sensitivity test would lead one to recommend a regional allocation of public tubewell development which is significantly different from that derived on the basis of IACA's projections of output responses. For instance, greater optimism about the output responses attainable in the absence of public groundwater development would lead to reserving in the Punjab and in Peshawar, up to 1980, 60 percent of the acreage underlain by fresh groundwater and not yet committed to ongoing projects for private tubewell development. The regional allocations of the public tubewell project priorities determined by adherence to IACA's projections of output responses would only recommend the continuation of private groundwater development on 48 percent of that same acreage.

In short, then, it is not possible to express in the aggregate greater optimism about the productivity development attainable with private tubewells or under con-

TABLE 4-8
AGGREGATE EFFECTS OF CHANGES IN THE SIZE OF THE PUBLIC TUBEWELL PROGRAM DURING THE PERIOD 1965–1975

Size of the Program 1965–75 (no. of four-cfs wells)	No. of Public Wells Installed During 1975–85	Average Growth Rates of Gross Production Value 1965–75	1975–85
25,000	5,500	5.5	5.3
22,600	7,900	5.4	5.4
20,000	10,600	5.3	5.6
17,500	13,200	5.2	5.5
15,000	15,586	5.0	5.5

ditions of continued underirrigation, without a review of the priorities for public tubewell development.

If it is, for instance, projected that the deferred project areas can, as a result of concentrated efforts, attain an improvement in the GPV per cropped acre of 3.5 percent per annum instead of 2.5 percent per annum as projected by IACA in their formulation of project priorities, it is a logical consequence that such upward revision also affects the comparative advantage of public tubewell development over continued private groundwater development, and thus, affects the priorities for public tubewell development. To the extent that the output responses per cropped acre employed in this sensitivity test follow in a simplified form the Study Group's modifications of the IACA projections set forth in Volume II, the results of this test may be considered indicative of the direction in which these modifications affect project priorities.

Project Priorities and the Effects of Specific Resource Limitations

To demonstrate the effect of the specific resource limitations considered in the linear programming analysis upon the determination of particular project priorities, this part of the Paper presents two conventional project evaluations based on the same data which defined the alternative projects in the linear programming analysis. These illustrative project evaluations first value all project inputs at market prices without regard to those input prices which may significantly deviate from their scarcity values. Next, the evaluation considers the cost of the limiting resources required by the respective projects in terms of their scarcity value as computed by the linear program.

This demonstration shows that the choice between public and private groundwater development in the case of Dipalpur and Begari Sind commands would lead to less than optimal use of scarce resources if the choice is made on the basis of the conventional project evaluations with the use of "market" prices. Simultaneously, these sample project evaluations provide some insight into the ways in which the linear programming analysis determines the priorities for the "best" or "optimal" investment program. The project evaluations presented below consider the choice between three alternative courses of public action: public development of the usable groundwater in the respective canal command by 1971, 1980 or after 1985. In the case of postponed public investment, private tubewell development is projected to continue. These alternatives are discussed in detail in Appendix 4-1.

The Case of Dipalpur Below BS Link Command

In the case of the Dipalpur below BS Link command we are dealing with an area which comprises 0.611 million acres of CCA. The area is completely underlain by usable groundwater. Fifty-nine percent of the area is endowed with groundwater of less than 1,000 ppm TDS. The command receives at present nonperennial surface water supplies. (For more details, see Volume II, Annex 4-1.)

The public tubewell project would develop the usable groundwater through the installation of public tubewells beginning 1970. These tubewells would be operated so as to integrate groundwater use up to balanced recharge with surface water supplies. The project formulation assumes that the latter supplies are limited only by the existing capacity of the distribution system.

In the absence of a public tubewell project it is assumed that private groundwater development will continue to support an extension of cropped acreage as well as the application of yield-growing inputs on acreage benefiting from private well supplies.

The net benefits, defined as gross production value minus farm costs, which are projected to be generated by these alternative courses of development are summarized in Table 4-9. The "with the project in 1971" benefit stream would be supported by capital expenditures for the continued buildup of private pumping capacity until 1970, together with expenditures for the replacement requirements of the private pumping capacity in existence by 1965. The present worth of these capital expenditures would be Rs. 25 per acre of CCA. Beginning 1970, the benefit stream would be supported by the installation of 800 four cfs-equivalent wells. These wells are assumed to be installed over the period 1970–75. Given a life of 20 years for the installation, the wells would have to be replaced during the period 1985–95. The present worth of these capital expenditures would be Rs. 81.5 per acre of CCA, discounting at 8 percent to 1965. The operation and maintenance of the private tubewell capacity supporting the benefit stream up to 1975 would cause an expenditure stream equal to Rs. 65 per acre CCA, present worth at 8 percent, as of 1965. The operating and maintenance cost of the public tubewell project would amount to an expenditure stream equal to Rs. 88 per acre of CCA, present worth at 8 percent as of 1965. In total, the projected net benefit stream equaling Rs. 3387 per acre of CCA, present worth, requires capital expenditures and outlays for operation and maintenance equal to Rs. 260 per acre CCA, present worth.

The "with the project after 1985" benefit stream is supported by the following projected buildup of private tubewell capacity:

1965, number of private wells in existence:	1,470
1975, number of private wells projected to be in existence:	4,060
1985, number of private wells projected to be in existence:	5,120

TABLE 4-9
NPV IN Rs. PER ACRE CCA

Reference Year	With the Project in 1971	With the Project in 1980	With the Project after 1985
1965	166	166	166
1970	207	207	207
1975	367	249	249
1985	531	531	351
1995	638	638	638
Present Worth of Net Benefit Stream[a]	3,656	3,250	2,959

[a] Interpolating linearly.

The capital cost of installing and maintaining these levels of private pumping capacity would be equal to Rs. 56 per acre of CCA, present worth at 8 percent as of 1965. For the period 1985–95, the benefit stream reflects the transition from private to public exploitation of the aquifer. The cost of installing 800 four-cfs wells during the period 1985–95 would be Rs. 16 per acre of CCA, present worth. The operation and maintenance of the private tubewell capacity would cause an expenditure stream equal to Rs. 171 per acre of CCA present worth at 8 percent as of 1965. Likewise the operation of the public tubewell project introduced during the period 1985–95 would cost Rs. 9 per acre of CCA, present worth. Thus, the benefit stream generated without the early public project would require capital expenditures and outlays for operation and maintenance with a total present worth of Rs. 252 per acre of CCA.

Finally, the intermediate timing of the project in 1980 would require outlays for continued private tubewell development up to 1980 and public groundwater development thereafter which total Rs. 235 per acre of CCA, present worth.

The cost and benefit streams generated by the alternative timing of a public tubewell project in Dipalpur below BS link command are compared in Table 4-10. As this table shows, the incremental benefits attainable through early implementation of a public tubewell project in Dipalpur below BS Link command would, according to all conventional decision rules, lead to the recommendation that project coverage be provided to this area within the context of the 1965-75 public tubewell program.

However, the programming approach has alerted us to the need for a proper valuation of a project's draft on the economy's limiting resources. In this analysis we singled out the effect of several of the resources which limit Pakistan's agricultural development, i.e. foreign exchange, administrative and engineering capability, and surface water during months of low river flow.

The shortage of administrative and engineering capability found its expression in the judgment of the Special Study consultants that during the period 1965–75 Pakistan would not be able to install more than a total of 20,000 four-cfs wells. We know from the analysis that during that same period public tubewell projects requiring more than 20,000 four-cfs wells could be economically justified. This means that in the allocation of the scarce public wells the scarcity value (shadow price) of the scarce public implementation capacity has to be considered. In other words, the public project cost considered in the project evaluation up to now understates the public project's claim upon some of the economy's scarcest resources. The linear programming analysis computed a scarcity value for the com-

TABLE 4–10
COMPARISON OF INCREMENTAL BENEFITS AND COST
(Rs. per acre CCA)

	Total Benefits	Total Direct Cost	Incremental Benefit	Incremental Cost
1. With the Project after 1985	2,959	260		
			(2)–(1): 291	(2)–(1): -25
2. With the Project in 1980	3,250	235		
			(3)–(2): 406	(3)–(2): 17
3. With the Project in 1971	3,656	252		

posite of "inputs" required to implement an increase in the size of the public tubewell program during the period 1965–75 of Rs. 194,000 present worth per well. Given this valuation, we should charge against this public tubewell project the economic cost of the resources which were required to implement the required number of public wells. Since this project comprises 800 wells, the total additional project "cost" would be Rs. 155 million present worth or Rs. 254 per acre of CCA present worth.

Furthermore, we have to consider that the two alternative modes of developing the acreage of Dipalpur below BS Link command differ in their respective claims upon surface water during the rabi period. While continued private development would generate the projected benefit stream with nonperennial canal supplies supplemented by private tubewell pumping, the public project would operate with an integrated ground and surface water budget requiring higher rabi surface water supplies in 1975 and 1985 respectively. In the linear programming analysis the total availability of rabi surface water during the period 1965–75 was limited to the unregulated river flows augmented by the storage releases from Mangla and Chasma. For this level of rabi surface water availability we found that an increase in the available surface water storage capacity by say one acre foot would allow for a change in the input mix of the total investment program so as to increase the present value of the aggregate net benefits of the optimal investment program by Rs. 257. This means that a project, the rabi surface water requirements of which increase over the 10 years from 1965–75 from zero to one acre-foot per acre should be charged Rs. 257 per acre present worth for the use of this scarce rabi surface water. The value of Rs. 257 represents the opportunity cost of this water use to the total system. Along similar lines we computed that a project which increases gradually in its rabi surface water requirements from 1975–85 by one acre-foot per acre should be charged Rs. 17 per acre present worth for the use of this water. A comparison of the water budgets which correspond to the alternative timing of the public project shows that the imputed costs for the use of scarce rabi surface water require the following increases in project costs:

With the project in 1971:	Rs. 293 per acre CCA, present worth
With the project in 1980:	Rs. 38 per acre CCA, present worth
With the project after 1985:	Rs. 17 per acre CCA, present worth

Finally, it is necessary to allow for the scarcity value of foreign exchange, both in terms of its opportunity cost to agriculture, as well as to the economy as a whole. We found in the linear programming analysis that a foreign exchange availability to the agricultural sector of $65 million and $114 million in the reference years 1975 and 1985 would imply a scarcity value of approximately Rs. 9.52 to the dollar in the agricultural sector. This value would seem to be approximately in line with the scarcity value of foreign exchange to the economy as a whole. If we impute this scarcity value to the import requirements implied by the cost stream related to the alternative timing of the public project, the following increases in project cost would be required:

With the project in 1971:	Rs. 115 per acre CCA, present worth
With the project in 1980:	Rs. 119 per acre CCA, present worth
With the project after 1985:	Rs. 107 per acre CCA, present worth

Thus, allowance for the imputed cost of the limiting resources singled out in this analysis would yield the following project costs per acre of CCA as set forth in Table 4-11. A comparison of incremental benefits and costs, set out in Table 4-12, shows, that implementation of the public project around 1980 would be preferable to either alternative timing of the public project. Thus, a proper valuation of the limitational resources used by each of the alternative courses of action considered in this evaluation would lead one to the conclusion that a postponement of public tubewell investment in Dipalpur below BS Link command from 1971 to 1980 would represent a more economic use of the scarce resources available to Pakistan during the period 1965–85.

The Case of Begari Sind, Usable Groundwater Zone

In the case of the usable groundwater zone of Begari Sind command we are dealing with an area which comprises 0.349 million acres of CCA. The area is completely underlain by usable groundwater of less than 1,000 ppm TDS. At present, the command receives nonperennial surface water supplies.

TABLE 4–11
PRESENT WORTH OF COST STREAMS RELATED TO GROUNDWATER DEVELOPMENT IN DIPALPUR BELOW BS LINK
(Rs. per acre CCA)

	With the Project In 1971	With the Project In 1980	With the Project After 1985
I. *Direct Costs*			
Capital and Other Expenditure	260	235	252
II. *Imputed Cost*			
Implementation of Public Tubewell Project Comprising 800 4-cfs Wells:	254	—	—
Scarce Rabi Surface Water Use:	293	38	17
Adjustment for Imputed Cost of Foreign Exchange Component:	115	119	107
Total Imputed Cost	662	157	124
Total	922	392	376

TABLE 4–12
COMPARISON OF INCREMENTAL BENEFITS AND COSTS INCLUDING IMPUTED COSTS
(Rs. per acre CCA)

	Total Benefits	Total Cost	Incremental Benefits	Incremental Cost
3. With the Project in 1971:	3,656	922		
			(3)–(2): 406	(3)–(2): 530
2. With the Project in 1980:	3,250	392		
			(2)–(1): 291	(2)–(1): 16
1. With the Project after 1985:	2,959	376		

The public tubewell project would develop the usable groundwater through the installation of public tubewells beginning in 1970. These tubewells would be operated so as to integrate groundwater use up to balanced recharge with surface water supplies. The project formulation assumes that full agricultural development of this area with a perennial cropping pattern can be achieved without rabi surface water supplies.

In the absence of a public tubewell project we assume that private groundwater development will continue to support an extension of cropped acreage as well as the application of yield-growing inputs on acreage benefiting from private well supplies.

The net benefits, defined as gross production value minus farm costs, which are projected to be generated by these alternative courses of development are summarized in Table 4-13. The "with the project in 1971" benefit stream would be supported by capital expenditures for the continued buildup of private pumping capacity until 1970, together with expenditures for the replacement requirements of the private pumping capacity in existence by 1965. The present worth of these capital expenditures would be Rs. 5 per acre of CCA. Beginning 1970, the benefit stream would be supported by the installation of 768 four-cfs-equivalent wells. These wells are assumed to be installed over the period 1970–75. Given a life of 20 years for the installation, the wells would have to be replaced during the period 1985–95. The present worth of these capital expenditures would be Rs. 137 per acre of CCA discounted at 8 percent to 1965. The operation and maintenance of the private tubewell capacity supporting the benefit stream up to 1975 would cause an expenditure stream equal to Rs. 9 per acre CAA present worth at 8 percent as of 1965. The operating and maintenance cost of the public tubewell project would amount to an expenditure stream equal to Rs. 148 per acre of CCA present worth at 8 percent as of 1965. In total, timing of the project in 1971 would require capital expenditures and outlays for operation and maintenance equal to Rs. 299 per acre CCA present worth.

TABLE 4–13
NET PRODUCTION VALUE, BEGARI SIND
(Rs. per acre CCA)

Reference Year	With the Project in 1971	With the Project in 1980	With the Project after 1985
1965	91	91	91
1970	91	91	91
1975	199	91	91
1985	152	280	147
1995	601	601	601
Present Worth of Net Benefit Stream at 8 percent as of 1965[a]	2,184	1,677	1,461

[a] Interpolating linearly.

The "with the project after 1985" benefit stream is supported by the following projected buildup of private tubewell capacity:

1965, number of private wells in existence:	90
1975, number of private wells projected to be in existence:	520
1985, number of private wells projected to be in existence:	790

The capital cost of installing and maintaining these levels of private pumping capacity would be equal to Rs. 13 per acre of CCA present worth at 8 percent as of 1965. For the period 1985–95 the benefit stream reflects the transition from private to public exploitation of the aquifer. The capital cost of installing 768 four-cfs wells during the period 1985–95 would be Rs. 27 per acre of CCA present worth. The operation and maintenance of the private tubewell capacity would cause an expenditure stream equal to Rs. 43 per acre of CCA present worth at 8 percent as of 1965. Likewise the operation of the public tubewell project introduced during the period 1985 to 1995 would cost Rs. 15 per acre of CCA, present worth. Thus, the benefit stream generated without the early public project would require capital expenditures and outlays for operation and maintenance with a total present worth of Rs. 98 per acre of CCA. Finally, the intermediate timing of the project in 1980 would require outlays for continued private tubewell development up to 1980 and public groundwater development thereafter which total Rs. 165 per acre of CCA.

The cost and benefit streams generated by the alternative timing of a public tubewell project in the usable groundwater zone of Begari Sind command are compared in Table 4-14. As this table shows, the incremental benefits attainable through early implementation of a public tubewell project in Begari Sind command would, according to all conventional decision rules, lead to the recommendation that project coverage be provided to this area within the context of the 1965–75 public tubewell program.

However, the programming approach would alter those results somewhat. A scarcity value for the composite of "inputs" required to implement an increase in the size of the public tubewell program during 1965–75 of Rs. 194,000, present worth, per well. Given this valuation, we should charge against this public tubewell project the imputed cost of the resources which were required to implement the required number of public wells. Since this project comprises 768 wells, the total

TABLE 4–14
COMPARISON OF INCREMENTAL BENEFITS AND COSTS
(Rs. per acre of CCA)

	Total Benefits	Total Direct Cost	Incremental Benefits	Incremental Cost
With the Project after 1985:	1,461	98		
			(2)–(1): 216	(2)–(1): 67
With the Project in 1980:	1,677	165		
			(3)–(2): 507	(3)–(2): 134
With the Project in 1971:	2,184	299		

additional project cost would be Rs. 149 million, present worth, or Rs. 427 per acre of CCA, present worth.

No allowance for the imputed value of rabi surface water deliveries has to be considered since all alternative courses of action considered for Begari Sind have been formulated on the basis of a water budget based on nonperennial surface water supplies.

It is however necessary to allow for the scarcity value of foreign exchange, of approximately Rs. 9.52 to the dollar in the agricultural sector. If we impute this scarcity value to the import requirements implied by the cost streams related to the alternative timing of the public project in Begari Sind Command the following increases in project cost would be required:

With the project in 1971:	Rs. 134 per acre of CCA, present worth
With the project in 1980:	Rs. 80 per acre of CCA, present worth
With the project after 1985:	Rs. 45 per acre of CCA, present worth

Thus, allowance for the imputed cost of the limiting resources singled out in this analysis would yield project costs per acre of CCA as set forth in Table 4-15.

As Table 4-16 shows, implementation of the public project around 1980 would be preferable to either alternative timing of the public project.

Thus, a proper valuation of the limitational resources used by each of the alternative courses of action considered in this evaluation would lead one to the conclusion that a postponement of public tubewell investment in Begari Sind command from 1971 to 1980 would represent a more economic use of the scarce resources available to Pakistan during 1965–85.

The Production Response of the Optimal Development Program

The economic analysis has shown that the production response to the optimal water development program amounts in the aggregate to a growth in the gross value of agricultural production[1] in the canal commanded areas of the Indus Basin equal to 4.5 percent per annum over 1965–75 and 6.4 percent per annum 1975–85. This projection of the attainable production response employs the cropping pattern

[1] Expressed in current prices. The prices used were IACA's estimates of 1964/65 farm-gate prices. IACA assumed decreasing prices for rice because of shifts in consumptive patterns, and increasing prices for meat reflecting improvements in quality.

TABLE 4–15
Comparison of Incremental Benefits and Costs
(including imputed costs)
(Rs. per acre of CCA)

	Total Benefits	Total Cost	Incremental Benefit	Incremental Cost
3. With the Project in 1971:	2,184	860		
			(3)-(2): 507	(3)-(2): 615
2. With the Project in 1980:	1,677	245		
			(2)-(1): 216	(2)-(1): 102
1. With the Project after 1985:	1,461	143		

and the acceptance rates and output responses to agricultural inputs other than water as set forth by the Special Study consultants.

The projected growth in the gross value of agricultural production in the Indus Basin would translate into a growth of irrigated agriculture's contribution to the gross regional product of slightly below 4 percent per annum during 1965–75 and between 5.5–6 percent per annum during 1975–85.

The significantly lower rate of growth of agriculture in the areas outside the Indus Basin would reduce the rate of growth of agricultural production for West Pakistan as a whole below those attainable in the Indus Basin.

The official planning target set forth by the Government of Pakistan in the Perspective Plan Documents is an average annual growth of the agricultural sector's contribution to gross regional product (factor cost) of 5.5 percent over 1965–85.

Given such a discrepancy between the growth targets of the Government and the production responses to a development program judged to be feasible during the period for which these targets have been formulated, it is necessary to examine in detail the various constraints which, in the view of the Special Study consultants, are limiting the attainable agricultural output growth.

During 1965–75, the aggregate output response to the proposed water development program can be attributed to ongoing projects, proposed projects and to the remainder of the irrigated acreage as set forth in Table 4-17. The overall growth of cropped acreage attained from project coverage during the period 1965–75 reflects the size of the public tubewell and canal remodeling program, as well as IACA's judgment about the speed with which additional irrigation supplies can be translated into increased cropped acreage on a constant CCA base. The output growth projected for the nonproject area will be generated predominantly by those yield improvements which are judged by IACA to be attainable through increased and improved farm inputs *without* increased irrigation supplies. However, this residual category also includes areas endowed with usable groundwater in which private tubewell development is projected to continue. If we assume that one private tubewell will on the average cover about 80 acres of CCA, the 19,500 additional private tubewells projected for 1965–75 in the nonproject areas would provide ade-

TABLE 4–16
PRESENT WORTH OF COST STREAMS, GROUNDWATER DEVELOPMENT IN BEGARI SIND COMMAND
(Rs. per acre of CCA)

	With the Project In 1971	With the Project In 1980	With the Project After 1985
I. *Direct Cost*			
Capital and Other Expenditures:	299	165	98
II. *Imputed Cost*			
Implementation of Public Tubewell Project Comprising 768 Wells	427	—	—
Adjustment for Imputed Cost of Foreign Exchange Component:	134	80	45
Total Imputed Cost:	561	80	45
Total	860	245	143

TABLE 4-17
AVERAGE ANNUAL GROWTH RATES, 1965-75

	CCA (million acres)	Gross Production Value (%)	Cropped Acreage (%)	Gross Production Value per Cropped Acre (%)
Ongoing Projects	5.4	6.3	2.9	3.4
Proposed Projects	7.6	7.0	3.3	3.6
Residual CCA	16.4	2.7	—	—
Indus Basin	29.4	4.5	—	—

quate irrigation supplies for about 1.56 million acres. Together with the 10,200 wells in existence in the nonproject areas in 1965, private well supplies would be available by 1975 to about 2.4 million acres, or 15 percent of the nonproject CCA.

Apart from the intensity growth supported by private tubewell supplies, the growth of output in nonproject areas has been projected to come from improvements in the production of a largely constant cropped acreage under conditions of continued underirrigation. By and large therefore, the limited growth of output in the nonproject areas reflects quite directly the shortage of irrigation supplies during the rabi period.

Alternative assumptions about agricultural productivity growth, in particular under conditions of continued underirrigation and on acreage benefiting from private tubewell supplies, would lead to a higher rate of growth of agricultural output. The aggregate output response of the program based upon the alternative projections of productivity growth (see page 18) can be attributed to ongoing projects, proposed projects and the remainder of the irrigated acreage as set forth in Table 4-18. The aggregate output response attainable with these assumptions shows that, even with considerably faster productivity growth in areas which before 1975 are not scheduled to benefit from any improvement in their irrigation supplies, and even further with an outstanding performance of the private tubewell farmers, it is not possible to attain the planned target growth rate for the agricultural sector.

Turning next to the implementation constraints that circumscribe the size of the public water investment program, we find that, for instance, a much larger public water development program for the period 1965-75—installing 25,000 four-cfs wells and remodeling 1.3 million acres of CCA—would raise the average annual growth of gross production value during the period 1965-75 from 4.5 percent to 4.8 percent. Table 4-19 shows the growth in agricultural output (GPV) which is

TABLE 4-18
AVERAGE ANNUAL GROWTH RATES DURING THE PERIOD 1965-75
(Alternative Projections of Productivity Growth)

	CCA (million acres)	GPV	Cropped Acreage	GPV per Cropped Acre
Ongoing Projects	5.4	7.3%	2.9%	3.4%
Proposed Projects	7.5	6.8%	3.2%	3.5%
Residual CCA	16.5	4.1%		
Indus Basin	29.4	5.3%		

TABLE 4-19

AGGREGATE EFFECTS OF CHANGES IN THE SIZE OF THE PUBLIC TUBEWELL PROGRAM, 1965–75[a]

No. of 4-cfs Wells	Public Wells Installed	Private Tubewells Projected for 1975[b]	Average Growth Rates of GPV	
			1965–75	1975–85
26,500	6,400	14,000	4.8	6.1
25,000	6,880	16,500	4.8	6.1
22,180	9,700	28,000	4.6	6.2
21,010	10,860	28,700	4.5	6.3
20,000	11,860	30,100	4.5	6.4
18,150	13,700	33,100	4.5	6.5
16,410	15,350	38,000	4.2	6.6
15,000	16,780	41,000	4.1	6.6

[a] All other constraints at the levels discussed in Part B.

[b] Assumes *complete* displacement of private wells by public wells in public tubewell project areas by 1975.

projected to be attained with public tubewell program of different sizes. The table shows that the impact of an enlargement of the public tubewell program upon the aggregate growth of agricultural output during the period 1965–75 diminishes with the size of the public program. This reflects the fact that, within a larger public tubewell program, public wells would increasingly displace a very active development of private tubewell irrigation. It also reflects the shortage of rabi surface water supplies before 1975, in that in the formulation of many public tubewell projects, especially those involving groundwater quality requiring mixing, rabi surface water is an input complementary to groundwater supplies.

Nevertheless, the analysis shows that an increase in the first period growth rate is attainable through the implementation of a larger public tubewell program. However, the question is whether a step-up in public tubewell implementation should be attempted in order to implement a public program in excess of 20,000 wells. On the basis of the shadow prices computed by the linear program on the public tubewell implementation constraint for different sizes of public tubewell program, it is possible to derive a marginal benefit/cost ratio for public tubewell investment within the context of public tubewell programs of alternative sizes. These benefit/cost ratios are shown in Table 4-20.

The table tells us that if it were possible to achieve an increase in the public sector's capability to implement a larger public tubewell program *without* an increase in the average *economic* cost of implementation (administrative, engineering, planning resources, skilled manpower etc.) per tubewell, then, and only then, would it pay to expand the public tubewell program to comprise the installation of 26,500 public wells by 1975. However, the judgment of IACA that the respective Pakistani authorities will not be able to install more than a total of 20,000 four-cfs wells by 1975 (with electrification of this total lagging by about one year) must be interpreted to mean that for a tubewell program in excess of this total the marginal economic cost of implementing an additional public project rises very sharply. In terms of the table, this would mean that the maximum economically justifiable public tubewell program, considering the economic cost of all resources, would be below a program comprising the installation of 26,500 four-cfs wells by 1975. This would be especially so if a campaign for the implementation of a larger water

TABLE 4–20
THE MARGINAL BENEFIT/COST RATIO PER PUBLIC TUBEWELLS, AS DEPENDENT ON THE SIZE OF THE PROGRAM FOR 1965–75[a]

No. of 4-cfs Wells	Marginal Benefit/Cost Ratio[b]
15,000	2.8:1
16,410	2.8:1
18,150	2.6:1
20,000	2.5:1
21,010	2.4:1
22,180	2.3:1
25,000	1.7:1
26,500	1:1
above 26,500	<1

[a] All other constraints set at the levels discussed in Part B.

[b] Defined as the increase in GPV minus farm costs attributed by the linear program to the implementation of one additional public 4-cfs well divided by the cost of installing one four-cfs well in 1970 plus the cost of operating and maintaining same over the period 1970–95.

investment program runs the risk of detracting from the significant changes in farm management and practices which have to be brought about to justify even the proposed volume of water investment.

Turning to the projected output response for the proposed water development program during 1975–85, we find that the output response reflects the removal of most irrigation supply constraints in interaction with the gradually increasing absorption of other agricultural inputs. The water investment program foresees the completion of the Tarbela reservoir around 1975, the completion of the Sehwan-Manchar Storage Project around 1980, the remodeling of canals serving a total of five million acres CCA, and the completion of the economically justified public tubewell program involving the installation of about 12,000 four-cfs wells in addition to the 20,000 scheduled for installation before 1975. In a number of areas which are projected to achieve a high density of private tubewells, the private exploitation of usable groundwater is projected to be continued until the period 1985–95, when all private wells are projected to be superseded by public development of the usable aquifer.

Given the net benefit response to additional surface water storage capacity provided by 1980, the analysis shows that the inclusion of Sehwan-Manchar in the storage program in 1980 instead of 1985 yields a ratio of incremental benefits to incremental costs of the total program, including surface water storage, of 1.14:1.[1] This result, however, depends very crucially upon the correctness of IACA's position that the Eastern Nara South canal command, comprising 1.6 million acres of CCA, of which over 70 percent has a groundwater depth of less than 10 feet, can be given, by 1980, additional rabi surface water supplies of about one MAF annually measured at the watercourse. The drainage project proposed by IACA

[1] Valuing the foreign exchange component of the investment program at Rs. 9.52 to the dollar.

for this area will not be completed before 1985. Any shortfall in the projected output response to the additional surface water supplies, due to an aggravation of the problems of waterlogging, would make it questionable whether the scarce surface water should be used in Eastern Nara South, and, furthermore, given the projected capacity for the useful absorption of rabi surface water in other areas, whether the timing of Sehwan-Manchar before 1985 remains justified.

Given this water development program and the projected growth of agricultural productivity per cropped acre, the gross value of agricultural production is projected to grow during 1975–85 at an average annual rate of 6.4 percent per annum. Again, the question should be raised about possible measures to attain a further acceleration of agricultural growth during that period. As regards water investment, growth of cropped acreage and agricultural production is confined to 6.4 percent per annum by two binding constraints: the availability of rabi surface water, i.e. the availability of surface storage capacity, and the size of the canal remodeling program, which, following the judgment of IACA, has been limited to five million acres. Taking these constraints one by one, our analysis shows that the provision of additional storage capacity before 1985, say in the form of Raised Mangla, without a significantly larger canal remodeling program would represent an uneconomic use of scarce resources if we accept the output responses to water projected by IACA for 1975–85. Regarding the other constraint, the size of the canal remodeling program during 1975–85, we find that an increase in the size of the canal remodeling program in this period, even without provision of additional surface water storage capacity, would appear to be highly beneficial because of a high scarcity value for the composite of "inputs" required to step up public implementation capacity in this field; the scarcity value of these inputs ranges from one to eight times the capital cost of canal remodeling, depending upon the canal command requiring remodeling. Finally, it should be reemphasized that the output response to the projected water investment assumes that, in a large number of canal commands, *average* cropping intensities above 130 percent will be reached. The Special Study consultants have stressed that the transition to average cropping intensities above 120-130 percent will be a slow process because of the required reclamation of waste land outside the farm area which is often seriously salt-affected. Considering further the size of the drainage program, both horizontal and vertical, which has to be implemented in order to support the projected yield and intensity growth, it can be stated that the justification of the whole water investment program, in particular the investments scheduled for 1965–75, depends crucially upon the realization of the output responses to water and other agricultural inputs projected as attainable during 1975–85. Stating it differently, the results of this analysis which pertain to the optimum size of the water investment program depend crucially upon the assumption that IACA's projections of the attainable growth of value productivity per acre cropped are realistic. Any upward or downward revision of these projections would entail a reconsideration of the optimum size of the water investment program.

Furthermore, if a significant acceleration of output growth over and beyond that projected in this analysis is judged to be attainable, an "effective demand" constraint may become operative which would require that farm inputs and water investment be considered as substitutes for each other. The same approach would have been necessary had the planning of agricultural development been carried out in explicit recognition of a binding financial constraint on development expenditures in the agricultural and water sector.

Economic Evaluation of the Effects of a Postponement of the Tarbela Project from 1975 to 1985

In the evaluation of the water investment program for 1975–85, two basic questions are of concern: the amount of surface storage justified and the source of this water. The state of project preparation made it possible to consider, in addition to the Tarbela Project, the raising of Mangla Dam and the Sehwan-Manchar Project as possible sources of incremental rabi surface water supplies during 1975–85. The amount of water was determined from the marginal value of rabi irrigation supplies computed for different levels of total availability. The linear program analysis indicated that, before 1985, in addition to the releases from Mangla and Chasma, additional rabi supplies up to a total of about nine MAF (measured at the rim station) could be economically justified—i.e. would have a marginal benefit cost ratio approximately equal to one—given the cost of providing additional storage capacity and given the assumed economic cost of capital. The economic justification for this value of incremental rabi irrigation supplies was established by considering a storage program built around the completion of the Tarbela Project in 1975 and the completion of the Sehwan-Manchar Project before 1985. The possibility of overpumping was also considered in this analysis.

It is, however, possible that an alternative program could provide the justified volume of incremental irrigation supplies at a lower *average* cost for the entire nine MAF. This question can be reduced to an evaluation of the net benefits of introducing the Tarbela Project in 1975 as opposed to 1985. This evaluation utilizes the results of the linear programming analysis as well as the power systems study (described in Supplemental Paper No. 7).

In postponing mainstem storage, the loss of the annual live storage of the reservoir is not the only casualty. There would also be a loss of intraseasonal regulation capability, i.e. loss of storage which could serve to regulate the flows in the Indus during the scarce water period into a desirable pattern for irrigation. On the basis of the monthly surface water requirements (obtained as an average of the requirements estimated by IACA for 1975 and 1985) to be satisfied from the Indus and Kabul, it is possible to estimate that during November-April, the amount of this intraseasonal regulation averages 1.8 MAF during 1975–85. Under mean year conditions this regulation capability is approximately equal to the combined regulation capability of Sehwan-Manchar and Chasma. Finally, postponing Tarbela also means postponing that part of the annual usable recharge which can be attributed to Tarbela storage releases—for this exercise that part of the recharge which could be recovered by a public tubewell project during the scarce water period.

In terms of objectives, a valid alternative should compensate for a 10-year postponement of Tarbela, in such a way as to make it possible for West Pakistan to attain the same gross value of agricultural output in the reference years 1975 and 1985 as was found to be attainable with completion of Tarbela by 1975, with the size of the public tubewell and canal remodeling program. With the help of the linear program a valid alternative program was formulated. The program was built around Raised Mangla by 1975 instead of 1988 and Sehwan-Manchar by 1975 instead of 1980. In addition to these reservoirs, part of the public tubewell capacity is allocated to overpumping duty, which would take place in canal commands where the aquifer conditions appear to permit a gradual drawdown of the water-table by about 35 feet. In general, this approach seemed not beyond reason on the basis of IACA's studies. Under the topic of "Substitution of Surface Supplies by Pumping," IACA comments as follows on the overpumping possibilities in the Indus Basin:[1] "Tipton and Kalmbach in their SCARP IV report for WAPDA have shown that in the SCARP IV area of Upper Rechna Doab, even with full development, most of the present surface water deliveries between October and May could be replaced by tubewell supplies, so releasing ¾ MAF of surface water a year for use elsewhere in the Basin during this period when rivers are generally low. The SCARP IV area is one of the most attractive for permanent substitution but the principles would be applicable throughout the irrigated areas underlain by fresh groundwater."

Tubewell projects which appear able to overpump during 1975–85, on the basis of the criteria cited, would relate to the following areas:

Upper Chenab I and II (SCARP IV)
Pakpattan above SM I
Pakpattan above SM II
Dipalpur below BS
Lower Bari Doab
Lower Chenab I Development Area
Sidhnai I

In all of these areas, with the exception of Upper Chenab I, the extra pumping November-April is accomplished within the installed capacity of the regular tubewell project design as set forth by IACA, by this limitation the increased tubewell utilization remains reconcilable with the pumping capacity required to attain monthly watercourse requirements with surface water availabilities of four years out of five. In Upper Chenab I, the installed capacity had to be increased by 160 four-cfs wells to achieve the assumed surface water substitution.

The overpumping assumed for these projects would involve additional costs both in the form of extra capital requirements for the actual tubewells as well as increased operating costs for power to pump from the greater depths. As long as the overpumping is accomplished within the installed capacity of a tubewell project which was designed to balance recharge, the increased capital cost consists only of the cost of deeper installation to pump permanently from a lower water table. To account for this additional cost we have raised the investment cost of a four-cfs tubewell (as given by IACA in Annexure 7, p. 39) by 20 percent. The additional power cost caused by overpumping has been computed according to IACA formulas (Annexure 7, Table 5.6, p. 41). On this basis the power cost of a tubewell project used for overpumping would be raised by the additional power cost caused by drawing the water table down from a 12-foot to a 50-foot depth over 1975–85 and by the additional power cost incurred by having to pump from 50 feet instead of a 12-foot depth from 1985 in perpetuity.

[1] See IACA report, Annexure 7, Water Supply and Distribution, p. 8.

Summed over the 10 years 1975–85, the "overpumping projects" have a potential for surface water substitution, within the constraints imposed upon the maximum drawdown (35 feet), of about 23 MAF measured at the watercourse. These same "overpumping projects" have by 1985 in the aggregate an annual substitution potential of 5.8 MAF (measured at the watercourse) during the months November to April.

By 1985, the Tarbela reservoir[1] would provide storage releases during the scarce water period (November-April) equal to 7.05 MAF. The raising of Mangla Dam[2] would by 1985 provide additional storage releases[3] equal to 3.18 MAF. This means that an annual capacity for surface water substitution through overpumping equal to 3.9 MAF (rim station equivalent) is needed to substitute for the direct supplies from early Tarbela. Provision of rabi flows from Raised Mangla, Sehwan-Manchar and overpumping would, at the same time, compensate for the loss of valuable recharge due to the postponement of the Tarbela releases.

We find from our analysis that an investment program which provides for the completion of Raised Mangla by 1975, the completion of Sehwan-Manchar by 1980, the inclusion of "overpumping projects" and the completion of Tarbela by 1985 would require three tubewell projects to be reformulated to allow for overpumping between 1975 and 1985: the project in Upper Chenab I and II (SCARP IV), the project in Pakpattan above SM II, and the project in the Lower Chenab Development area.

The need to provide for overpumping to compensate for the postponement of main stem storage would also justify the start of a public tubewell project designed for overpumping before 1975 in Sidhnai I. The implementation of these "overpumping projects" would require either the withdrawal of 900 four-cfs wells from other priority areas, or the release of the overall tubewell constraint. The linear program indicates that the best way to minimize the effects of withdrawing scarce public wells from other project areas so as to use them in overpumping projects would be to delay the complete Fordwah and Eastern Sadiqia II Project and Sidhnai II Project until after 1975. In addition, it would be necessary to defer further parts of the Bahawal Project. This reallocation of public tubewells would reduce the sum of the benefits attainable with a public tubewell program of the given size. In the analysis, all reductions in net benefits are charged against the "overpumping projects."

Considering irrigation aspects only, the cost of reallocating scarce inputs, including the cost of alternative reservoirs, so as to compensate for the postponement of Tarbela leads to a savings of Rs. 63 million, expressed in present worth at 8 percent as of 1965. This sum represents the net difference between the cost of providing the required rabi supplies with an investment program formulated around Tarbela in 1975 and an investment program formulated around Tarbela in 1985. The derivation of this net difference is set forth in Table 4-21.

The cost of overpumping, totaling Rs. 640 million, includes Rs. 300 million for the cost of overpumping proper, i.e. the cost of different tubewell installation and the cost of pumping from greater depth. The remaining Rs. 340 million accounts

[1] Drawdown level 1332.
[2] Drawdown level 1040.
[3] We are assuming a Tarbela-type release pattern for the storage increment provided by Raised Mangla.

TABLE 4–21
PRESENT WORTH OF COST STREAM RELATED TO STORAGE PROGRAM FORMULATED AROUND TARBELA IN 1975[a]
(Rs. Million)

Tarbela, 1975	1,833
Sehwan-Manchar, 1980	332
Raised Mangla,[b] 1988	162
	2,327

PRESENT WORTH OF COST STREAM RELATED TO STORAGE PROGRAM FORMULATED AROUND TARBELA IN 1985[a]
(Rs. Million)

Raised Mangla,[b] 1975	441
Sehwan-Manchar, 1980	332
Tarbela, 1985	851
Overpumping, 1975–85[c]	640
	2,264
Net difference	63

[a] Discounted at 8 percent, excluding Low Mangla and Chasma. All cost estimates have been abstracted from Gibb & Partners, *The Tarbela Project*, London, November 1966.

[b] Assuming adequate surplus kharif flows will be available to fill the reservoir.

[c] Assumes public tubewell program able to install 20,000 4-cfs wells during 1965–75.

for the opportunity cost of the tubewells withdrawn from other tubewell projects to complete the required number of "overpumping projects," as well as the opportunity costs of all other scarce inputs which were reallocated so as to minimize the effects of postponed main stem storage.

As pointed out above, postponement of main stem storage means not only postponement of storage which transfers water from kharif to rabi but it also means postponement of storage which could serve to regulate the flows in the Indus during the scarce water period into a desirable pattern for irrigation. In this analysis, only partial compensation is provided for this postponement of intraseasonal regulation capability. It was noted earlier that combined regulation capability of Sehwan-Manchar and Chasma is approximately equal to that provided by major main stem storage under mean year conditions. But, in fact, in the alternative investment program, Sehwan-Manchar is not introduced until 1980. Therefore analysis of the differential cost and benefits of the alternative investment programs has so far taken incomplete account of the economic value of the differential certainty of the canal deliveries that can be attained with the alternative program.

However, it is proposed that the two programs would become more comparable in the certainty of their benefits if the regulation capability of Sehwan-Manchar would be provided in 1975 instead of 1980. The increase in the present worth of the cost of the storage program due to earlier scheduling of Sehwan-Manchar, which is equal to Rs. 133 million, should be considered as an approximate valuation of the intraseasonal storage benefits of Tarbela Reservoir during 1975–85.

Such provision for the compensation of the intraseasonal storage benefits of Tarbela would more than compensate for the existing cost differential between the alternative programs. In fact, the program involving postponement of Tarbela would be Rs. 70 million more expensive.

There is also included (p. 188) an analysis of the effects of a larger tubewell program on priorities. It has similarly often been argued that the returns to investment in Tarbela would be sensitive to the size of the public tubewell program undertaken during the 1965–75 period. An investment program was therefore formulated on the assumption of Tarbela in 1975 but which is limited in the size of the public tubewell program to 17,700 wells. All other resource limitations were left unchanged. The impact of a postponement of Tarbela Project within the context of such a reduced tubewell program was then analyzed.

It was found that the cost of introducing overpumping projects so as to compensate for the postponement of Tarbela raises the cost of overpumping by Rs. 250 million to Rs. 890 million. It was concluded that any shortfall in the public sector's ability to implement public tubewell projects during the 1965–75 period would considerably enhance the comparative advantage of implementing the storage program formulated around Tarbela in 1975.

By the same token, if it were judged that the respective agencies and authorities were able to implement during the 1965–75 tubewell projects comprising a total of 22,750 wells instead of 20,000 wells, overpumping costs would be lower. According to our analysis, this would reduce the advantage of the "Tarbela in 1975 Program" by Rs. 170 million present worth.

Before it is possible to integrate these results with those of the analysis of the power aspects of the Tarbela Project, it is necessary to follow the power analysis in valuing the respective import components of the alternative storage programs at a scarcity price of foreign exchange equal to Rs. 9.52 to the dollar.

Starting with the cost of overpumping, we find from the linear programming analysis that the cost of the tubewells withdrawn from other tubewell projects in order to complete the required number of "overpumping" projects, as well as the opportunity cost of all other scarce inputs which were reallocated so as to minimize the effects of postponed main stem storage entails an increase in the foreign exchange cost of the program equal to $9 million present worth at eight percent. In addition, the extra capital cost of tubewell installations designed to pump from greater depth is estimated to entail additional import requirements equal to $3.8 million. A revaluation of these additional import requirements caused by overpumping using a rate of exchange twice the official rate would add Rs. 60 million present worth to the cost of overpumping.[1] It is further assumed that the foreign exchange component of the outlays for the construction of the various reservoirs considered in the alternative programs is 60 percent. Table 4-22 gives a comparison between cost streams which value the respective foreign exchange component at a rate of exchange set at Rs. 9.52 to the US dollar. As the table indicates after revaluation of the foreign exchange components of the alternative water investment programs, a net difference may be between the present worth of the alternative cost streams equal to Rs. 176 million. However, since the Tarbela Reservoir is a

[1] The foreign exchange cost of the additional pumping load has been considered in the power analysis.

TABLE 4–22
PRESENT WORTH OF COST STREAM RELATED TO STORAGE PROGRAMS FORMULATED AROUND TARBELA[a]
(Rs. Million)

A. Tarbela in 1975	
Tarbela, 1975	2,933
Sehwan-Manchar, 1980	531
Raised Mangla,[b] 1988	259
	3,723
B. Tarbela in 1985[a]	
Raised Mangla,[b] 1975	705
Sehwan-Manchar, 1975	780
Tarbela, 1985	1,362
Overpumping, 1975–85[c]	700
	3,547
Net difference	176

[a] Discounted at 8 percent excluding Low Mangla and Chasma. All cost estimates have been abstracted from Sir Alexander Gibb & Partners, *The Tarbela Project*, London, November 1966.
[b] Assuming adequate surplus kharif flows will be available to fill the reservoir.
[c] Assumes public tubewell program able to install 20,000 4-cfs wells during 1965–75.

multipurpose project, the results of the above analysis which focus upon irrigation benefits only cannot be given a meaningful interpretation by themselves, but have to be integrated with the results of a similar analysis focusing upon the power benefits. It should be noted that in the analysis of the power aspects presented below, the incremental power cost of overpumping has been analyzed as an integral part of the power program which was designed to be fully complementary with the "alternative" irrigation and surface storage program. Therefore, to avoid double counting in the joint consideration of irrigation and power aspects, overpumping cost computed above had to be reduced by Rs. 150 million present worth, which represents the incremental power cost of overpumping computed for an economic cost of power of Rs. 0.09 per kwh.

Electric Power Aspects

Two alternative programs of power development were prepared, both designed to meet a power load forecast which the Study Group considered consistent with other parts of the overall development program recommended. One was the best of several alternatives studied which included Tarbela in 1975, while the other—with Tarbela in 1985—was specially designed to be fully complementary with the "alternative" irrigation and surface storage program. The program with Tarbela in 1975 also included systemwide 380-kv interconnection in 1971 and addition of about 3,200 mw of thermal capability between 1966 and 1985, heavily concentrated at Mari and at Karachi; the 12 Tarbela power units were brought in relatively rapidly following completion of the dam, the last four being completed by 1980.

A power program modeled around completion of Tarbela in 1985 as discussed in Supplemental Paper No. 8, would be radically different from the Tarbela-in-1975 program. In the first place, raising the Mangla dam and adjusting the rule curve for the operation of the reservoir to a pattern that would be appropriate for a situation where some Mangla storage was being used to supply canal commands that would otherwise have been fed from the Indus has an important effect on the time pattern of capability and energy output of the Mangla power units. In the second place, substitution of a portion of the irrigation supplies that would have come from Tarbela with groundwater, by means of overpumping, involves a substantial increase in the pumping load that must be met by the program including delayed Tarbela in addition to the basic (i.e. nonpumping) and regular pumping loads if the net power benefits of the programs with Tarbela in 1975 and Tarbela in 1985 are to be the same. In the third place, postponement of Tarbela to 1985 might well eliminate and would certainly postpone the need for the expensive 380-kv transmission system included in the program with early Tarbela, since by the late 1980's the load of the Northern Grid alone would be large enough and growing rapidly enough to absorb most of the energy contribution of Tarbela within about seven years.

In order to derive figures for the capability and energy output of the Mangla units under the changed conditions, the operation of High Mangla Reservoir in a mean year was simulated manually by 10-day periods. The basic approach to operation of the reservoir was to develop a release pattern that was a combination of the agricultural consultants' release pattern for Mangla (applied to the 4.8 MAF of live storage of Low Mangla, with drawdown level of 1040 feet) and the agricultural consultants' release pattern for Tarbela (applied to the 3.5 MAF live storage that would be added by the raising of Mangla). Adjustments had to be made, particularly during the filling period, to ensure that the outflow through the dam during this period would at least be sufficient to meet the kharif irrigation requirements of the Jhelum-fed canal commands. The rule curve finally adopted for the study was one that would provide sufficient kharif irrigation water in a mean year and at the same time fill most of the reservoir by early August. Storing such a large proportion of flows in June and July meant that energy available in those months was severely curtailed. In years of low summer flow, filling of the reservoir would have to be drawn out longer, which would mean that the capability would increase more slowly between the time of maximum drawdown (early May) and the end of the kharif season (September). Nevertheless there seems to be little doubt that High Mangla could be filled, while at the same time the 1985 kharif requirements of the Jhelum-fed canal commands[1] were met, except possibly, in years of record such as 1940 when kharif flows on both the Chenab and the Jhelum were unusually low.

The addition to the power load forecast for overpumping had to be sufficient to cover the additional amounts of power required both for pumping more water in the rabi season to make up for the lack of Tarbela and for pumping from a greater depth throughout the year as a result of lowering the water table. It was estimated that this might total about 280 million kwh (including distribution losses) in 1980 and about 550 million kwh (including losses) in 1985. This additional energy requirement was distributed over the canal commands where overpumping would

[1] IACA's Comprehensive Report, Volume 5, Annexure 7—Water Supply and Distribution, p. 94.

be undertaken for supply of irrigation water from the groundwater aquifer. Monthly energy requirements were converted into peak loads by a 70 percent load factor—being about the average of the monthly load factors implied in the pumping load forecasts made by the Special Study consultants for the Northern Grid area in 1985. To err on the conservative side in assessment of the additional load, no allowance was made for interruption of the tubewell load. The result of these calculations was an addition to peak load in the critical months of March and May of 60 mw and 34 mw respectively in 1980 and 120 mw and 65 mw, respectively, in 1985.

As regards investment in the power sector (see Supplemental Paper No. 8), postponement of Tarbela from 1975 to 1985 permits elimination of the EHV transmission system included in programs with early Tarbela (total costs in the order of Rs. 480 million for which a substantial part of the justification is to enable more rapid absorption of Tarbela energy) but requires installation of about 4,300 mw of new thermal capacity—or about 1100 mw more than the program with Tarbela in 1975.

Furthermore, since a crucial determinant of the power benefits of Tarbela—and of having Tarbela at one time rather than another—is the cost to Pakistan of fuel for thermal generation, the Study Group adopted an approach to the pricing of thermal fuel that attempted to take into account the size of West Pakistan's indigenous fuel reserves, the potential for using them for purposes other than generation of electric power and the differences between power programs in the draft that they would make on the fuel reserves. The approach is described in detail in Supplemental Paper No. 8.

The total system costs of the alternative power programs, after adjustments described in Supplemental Paper No. 8, are shown in Table 4-23, discounted to 1965. The costs shown in the table cover all capital and maintenance and operating costs of power generation and transmission for 1966–85 together with fuel requirements valued according to the procedure described in detail in Supplemental Paper No. 8; they also cover the major differences in capital costs and fuel costs that would be involved in the period 1985–95 as a result of bringing in the Tarbela units in the years following 1985 instead of 1975–80. The costs are shown for the different assumptions with regard to the foreign exchange rate used in this Report and for the different assumptions regarding fuel reserves (and hence fuel prices). It is possible to indicate briefly the main components of the cost of postponement. The difference between the present worth costs of the two programs, when foreign ex-

TABLE 4–23
PRESENT WORTH COSTS OF POWER PROGRAMS INCLUDING TARBELA IN 1975 AND IN 1985
(Rs. million discounted at 8% to 1965, economic fuel prices)

	Current Est. Gas Reserves		Larger Gas Reserves	
	Current Exch. Rate	Shadow Exch. Rate	Current Exch. Rate	Shadow Exch. Rate
Tarbela 1975	3,784	5,255	3,208	4,679
Tarbela 1985	4,355	5,807	3,651	5,103
Costs of 10-year postponement	571	552	443	424

change is valued at the current scarcity price and fuel at the price series appropriate on the basis of current estimates of gas reserves, is indicated in Table 4-23 to be Rs. 552 million. In terms of capital costs of generation and transmission over 1966–85 (with the foreign component valued at this higher exchange rate), the program with Tarbela in 1985 actually shows a substantial saving of about Rs. 524 million over the program with early Tarbela. The cost of additional thermal capacity required to make up for lack of Tarbela in 1975–85 is much more than outweighed by the capital cost savings obtained by eliminating the need for the EHV transmission system and by postponing the Tarbela units. The total costs involved in the construction and operation of the amount of gas-pipeline capacity required for the postponed Tarbela program are estimated at about Rs. 167 million in present-worth terms, reducing the net capital cost saving over 1966–85 to about Rs. 357 million. This saving is much more than offset by the combined effect of the additional fuel costs involved—about Rs. 738 million, two-thirds of it in the 1975–85 period—and the additional capital cost of about Rs. 171 million involved after 1985 to finance installation of the Tarbela units instead of thermal units at that time. Thus, in summary, the net saving in capital costs over the whole period 1965–95 resulting from postponement of Tarbela is of the order of Rs. 190 million and this is more than outweighed by the extra fuel costs of about Rs. 738 million incurred by such a postponement. Of these extra fuel costs, about 70 percent is due to the extra quantity of thermal fuel required and about 30 percent due to the higher average used in this analysis.

There is another interesting aspect of the figures shown in Table 4-23. The savings resulting from early completion of Tarbela appear to be very insensitive to the foreign exchange rate used. In many analyses undertaken in the course of investigations, the power benefits of Tarbela have appeared quite sensitive to different assumptions regarding foreign exchange. The apparent inconsistency results from different approaches used in the valuation of fuel. The main alternative to Tarbela is thermal equipment, which is much cheaper than Tarbela units in terms of capital cost but expensive in terms of fuel. In many analyses, indigenous fuel is treated as a purely domestic cost item so that comparison of programs with and without Tarbela show much lower benefits to Tarbela when foreign costs are valued at a foreign exchange rate higher than the official one. Here, however, fuel has been treated more like a foreign resource in that its price has been made to depend on the foreign exchange burden of importing fuel when known domestic fuel resources are exhausted. The heavier fuel consumption of the "without Tarbela" (or in this analysis "with postponed Tarbela") case weighs more heavily against it.

Combined Irrigation and Power Aspects of Postponement

Table 4-24 considers both the irrigation and power aspects of a postponement of Tarbela for 1975 to 1985.

This comparison of the present worth costs of the alternative joint irrigation and power programs shows that the savings attributable to the completion of Tarbela in 1975 amount to between Rs. 100 and Rs. 500 million, depending upon the assumptions used in the above analysis. The validity of this comparison between alternative joint storage and power programs does of course rest on the assumption that if Tarbela were delayed, then the alternative program would be implemented.

TABLE 4-24
PRESENT WORTH COSTS OF ALTERNATIVE STORAGE AND POWER PROGRAMS FORMULATED AROUND TARBELA IN 1975 AND 1985
(Rs. million discounted at 8% to 1965, economic fuel prices)

	Current Estimate Gas Reserves		Larger Gas Reserves	
	Official Exchange Rate	Shadow Exchange Rate[a]	Official Exchange Rate	Shadow Exchange Rate[a]
Tarbela in 1975				
Storage Program	2,327	3,723	2,327	3,723
Power Program	3,784	5,255	3,208	4,679
Total	6,111	8,978	5,535	8,402
Tarbela in 1985				
Storage Program[b]	2,247	3,397	2,247	3,397
Power Program	4,355	5,807	3,651	5,103
Total	6,602	9,204	5,898	8,500
Saving attributable to completion of Tarbela in 1975 instead of 1985	491	226	363	98

[a] $1 = Rs. 9.52. [b] Includes the cost of overpumping between 1975 and 1985.

The Study Group believes that the alternative program represents a valid comparison for purposes of the economic evaluation of a postponement of Tarbela. Many of its components, such as High Mangla and the public tubewell schemes, have received considerable study in Pakistan. In combination they appear to be capable of meeting the irrigation requirements of the alternative development program even in years of low flow. It is true that there have been some historical years on the Jhelum when kharif flows would apparently have been inadequate to fill High Mangla, if drawn down to 1040 feet as assumed here, while at the same time meeting the kharif irrigation requirements of the Jhelum-fed canal commands. However, it appears to be reasonably certain that both the filling requirements and the kharif irrigation requirements could be fully met in the earlier years when the kharif irrigation requirements are smaller, and by the later years—say 1980–85—the extensive public tubewell fields will provide a sizable amount of flexibility for coping with years of low flow.

While the Study Group thinks that the alternative storage and power program may be technically feasible, it does also believe that the program formulated around the early completion of the Tarbela project has a degree of security that cannot be matched by the alternative. The Tarbela Project has been extremely thoroughly investigated, so the decision to complete it implies a fair degree of certainty that the reservoir's contribution to power and to irrigation supplies will indeed become available eight to nine years later. On the other hand, the use of public tubewell projects for overpumping would introduce a higher degree of uncertainty, since it would represent a new and yet untested form of operation of the irrigation system. Furthermore, as regards the power benefits of the Tarbela Project, the project is inherently so large in its contribution to power supplies that it provides a substantial margin for meeting unanticipated growth in demand. The same would apply to the temporary surplus storage capacity provided by Tarbela in the early years after its completion which has not been valued in this analysis.

In sum, the Study Group believes that the above analysis provides a reasonable valuation of the savings attributable to the completion of Tarbela in 1975 rather than in 1985, except for the additional value that should be attached to the greater degree of security that attaches to the program formulated around the completion of the Tarbela Project by 1975.

On this basis, taking the most realistic set of assumptions—a scarcity value of foreign exchange equal to twice the official exchange rate and the current estimate of natural gas reserves—the net savings attributable to the completion of Tarbela in 1975 instead of 1985 would be Rs. 226 million present worth. The Study Group concludes therefore that the least cost storage program which meets the irrigation and power requirements of West Pakistan would be a storage program formulated around the early completion of the Tarbela Project. With this economic evaluation, the Study Group reconfirms that the completion of the Tarbela Project by 1975 represents an economically justifiable investment decision in the context of the optimal program for water and power development in West Pakistan.

Conclusions Relating to the Study Group's Action Program

This section attempts to impose upon the linear programming analysis, the same assumptions as have been made in the course of the Study Group's formulation of the Action Program set forth in this Report. Thus, it should be noted at the outset that the results of the linear programming analysis discussed in this appendix have been obtained on the basis of assumptions which differ from those employed in the preceding parts of this supplement. Consequently, the project priorities pointed up by this analysis differ somewhat from those presented earlier. These changes in assumptions pertain to the comparative advantage of early public groundwater development in the Thal command and in the D.G. Khan and D.I. Khan Command. While IACA noted in its report on the "Thal Doab and Indus Right Bank Regional Development" (p. 29) that there is reason to believe that the data inputs used in its economic analysis overstate the benefits and understate the capital costs of public tubewell development in these two commands, only the project priority of D.G. Khan and D.I. Khan was corrected. The Study Group, in its review of the IACA program, applied the reasoning which led IACA to postpone public tubewell development in these commands to Thal command as well. While it would clearly have been preferable to correct these data inputs and repeat the analysis, rather than to correct the priority list, lack of time precluded an analysis based on corrected cost and benefit data.

To make it possible to compare the results of the linear program with the project priorities stated in the Action Program, it was necessary to proceed in this analysis as if it had been established on the basis of corrected data that these canal commands do not enter the priority list. In other words, the project selection was repeated, barring from the outset, the possibility of early public tubewell development in these commands. The elimination of these projects from the priority list frees over 3,000 scarce public tubewells previously allocated to these commands for reallocation, thus causing changes in the priority status of other project areas. After taking account of these adjustments the following projects were found to have priority for implementation within the context of a public tubewell program comprising the installation of 20,000 four-cfs wells (or equivalent) during 1965–75 (the following list should not be interpreted to imply a priority ranking of the projects):

Dipalpur above BS Link Project
Ravi Syphon-Dipalpur Link Project
(including canal remodeling)
Bahawal-Qaim Project
Fordwah and Eastern Sadiqia Project
Shujaabad Project
Shorkot-Kamalia Project
Panjnad Abbasia Project (including canal remodeling)
Sukkur Right Bank Project
Rohri North Project
Rohri South Project
Begari Sind Project

In addition to these project areas, the analysis indicates priority for public tubewell development before 1975 in Pakpattan above SM II, in the Lower Chenab Development Area (including subsequent canal remodeling) and in parts of Lower Bari Doab commands.

The analysis also shows that, should it be necessary to proceed with public tubewell development within the context of a smaller overall tubewell program of say, 17,500 tubewells, the following projects would best be postponed until after 1975:

First, the partial public groundwater development in Lower Bari Doab command; second, the Begari Sind Project; and third, the Sukkur Right Bank Project. Further reductions in the size of the public tubewell program would affect the priority position of Shujaabad Project, and of Bahawal-Qaim Project.

With regard to the tubewell-cum-canal remodeling project recommended by the analysis for the Lower Rechna Development Area, the analysis shows that a public tubewell project *per se* would have less justification than a tubewell project followed shortly by canal remodeling. This means that adherence to the IACA position that canal remodeling in the Lower Chenab command should be combined with the construction of a new cross Punjab Link Canal scheduled for after 1985 (IACA, Rechna Doab Regional Development, Volume 15, p. 37) would reduce the priority status of early public groundwater development in this area. However, on the basis of IACA data, the comparative advantage of public over private groundwater development is still strong enough to warrant full inclusion of this project in a public tubewell program comprising 17,500 wells.

Turning to the groundwater development projects recommended in the Action Program, we find that they add up to a total public tubewell program which would, including the tubewell requirements of the ongoing projects, lead to the installation of 19,700 wells during the remainder of the Third Plan period and during the Fourth Plan. According to the phasing of the tubewell projects indicated in Volume II, this program would bring about 17,350 wells into actual operation during the same period. While the total size of the tubewell program is comparable to that used in the linear programming analysis, a comparison of project content and priorities is complicated by the fact that the tubewell requirements of the project areas considered in the latter analysis differ from those considered in the formulation of the Action Program. This is due to the following differences in approach: first, the linear programming analysis uses the canal command as the basic area unit whereas the projects formulated in the Action Program often comprise contiguous parts of several canal commands. Therefore, the linear programming analysis can only confirm the priority of such projects to the extent that it shows a priority for a major component which is congruent with a canal command. For example, the Shorkot-Kamalia Project covers the Haveli commands as well as small parts of Lower Chenab I command and Lower Bari Doab. In this case, the linear programming analysis considers the priority for the Haveli component of this project directly, but the remaining parts of the project are only considered in the broader context of the priority of the canal command to which they belong. Thus, the linear program shows priority for the installation of 184 four-cfs wells in the Haveli command, whereas the Action Program accords priority to the larger Shorkot-Kamalia Project requiring 426 wells. Secondly, the tubewell requirements in the linear program analysis are expressed in terms of four-cfs wells or their equivalent, that is considering one two-cfs well in its claim upon public implementation capacity as equal to 0.75 four-cfs well. In contrast, the Action Program treats the installation of both types of well as equal in their claim upon implementation capacity. As a result of this difference, projects requiring two and three-cfs wells are considered in the respective analysis with different claims upon the public implementation capacity which circumscribes the size of the total tubewell program. Thirdly, in the case of Rohri North and Rohri South Projects, the Action Program includes the installation of extra pumping capacity in anticipation of the canal remodeling recommended to be undertaken after 1975. These three differences add up to a difference in total tubewell requirements of about 1,500 tubewells.

Keeping these complications in mind, the linear program analysis confirms the priority accorded in the Action Program to the following projects:

Dipalpur above BS Link Project
Ravi Syphon-Dipalpur Link Project including canal remodeling
Bahawal Qaim Project
Fordwah Sadiqia Project as far as the major Fordwah Sadiqia II component is concerned
Shujaabad Project as far as the Sidhnai II component is concerned
Shorkot-Kamalia Project as far as Haveli I and II are concerned
Panjnad Abbasia Project
Sukkur Right Bank Project
Rohri North Project
Rohri South Project
Begari Sind Project

The analysis further confirms the relatively weak priority position accorded in the Action Program to the projects Bahawal-Qaim, Begari Sind and Sukkur Right Bank by their deferred and partial inclusion in the Action Program.

The comparison of the priority lists shows disagreement with regard to the priority for early public groundwater development in Pakpattan above SM Link II command and in the Lower Rechna Development Area.[1] Furthermore, while there is agreement on the marginal nature of the priority for early public groundwater development in Diplapur below BS Link command and in parts of the Lower Bari Doab command, the linear program excludes the former from the priority list whereas the Action Program includes it. On the other hand, the Action Program excludes the start of a public tubewell project in Lower Bari Doab command whereas the linear program analysis recommends its partial inclusion.

Since the linear programming analysis seemed to give some indication that the project priorities were influenced by the benefits accorded to the surface water substitution potential ascribed to these tubewell projects, and since the speedy adoption of a mode of projects and system operation which would allow for the realization of these benefits is somewhat in doubt, the analysis was repeated subject to the assumption that projects initiated after 1969 will not realize benefits from surface water substitution before 1975. This version of the analysis shows that the relative priority for early public tubewell development in the usable groundwater zone of the Lower Chenab Development Area (part of the SCARP V project area) is not dependent upon the early realization of benefits from surface water substitution. The priority position of Pakpattan above SM Link II is somewhat reduced by the reduction in these benefits, however, not sufficiently to exclude this project from a total tubewell program comprising 20,000 wells.

As far as the priority of the Lower Chenab Development Area is concerned, it may be argued that the inclusion of this project within the priority list derived in the linear programming analysis is a direct result of the above difference in the total tubewell requirement of the priority projects. While the total difference between the requirements of the tubewell projects on which the analysis agrees is approximately equal to the number of tubewells required by the Lower Rechna Project, an adjustment of the tubewell requirements used in the linear programming analysis —bringing them in line with those used in the Action Program—would not eliminate the Lower Rechna Development Area from the priority list. As our analysis has shown, there are several projects (the partial project in Lower Bari Doab command, the Begari Sind Project and the Sukkur Right Bank Project) with priority status weaker than that of the Lower Rechna Project; these would be excluded from the priority list as a consequence of such an adjustment.

However, as has been discussed in Volume II, Chapter VIII, the Study Group tends to project a somewhat faster private tubewell development than projected by IACA and it also assumes higher rates of yield growth *independent* of increased water availability. To the extent that the data inputs of the linear programming analysis adhered to the IACA projections, these modifications introduced by the Study Group would tend to reduce the priority status of all areas with a strong ongoing

[1] Both areas were also found to have priority for early public tubewell development in the analysis of project priorities undertaken by the Special Study consultants. IACA, Volume 2A, Annexure 1, p. 26.

TABLE 4–25
COMPARISON OF PRIORITY IDENTIFICATION AND PROJECT PRIORITIES IN ACTION PROGRAM
(1965–75)

Name of Command/Project	Linear Program Analysis[a] CCA Covered	Linear Program Analysis[a] No. of 4 Cusec Wells Allocated	Linear Program Analysis[a] Canal Re-modeling	Consultant's Analysis[b] CCA Covered	Consultant's Analysis[b] No. of 4 Cusec Wells Allocated	Consultant's Analysis[b] Canal Re-modeling	Project Priorities in Action Program[c] Name	No. of Wells Proposed	Fresh	Mixing and Saline	Total	Re-modeling Proposed
	(million acres)		(million acres)	(million acres)		(million acres)			(million acres)			(million acres)
Dipalpur above B.S. Link	0.372	625	—	0.372	508	—	Dipalpur Above	630	0.344	0.028	0.372	—
Ravi Syphon Dipalpur Link	0.595	797	0.338	0.595	817	0.207	Ravi Syphon	780	0.257	0.338	0.595	0.338
Bahawal above MB Link	0.093	180	—	0.051	76		Bahawal Qaim[h]	924	0.335	0.187	0.522	—
Qaim				0.042	95							
Fordwah Sadiqia I	—	—	—	0.062	81		Fordwah Sadiqia	665	0.237	0.122	0.359	—
Fordwah Sadiqia II	0.297	550	—	0.298	496							
Pakpattan above SM II	0.347[d]	677	—	0.332	539							
Lower Bari Doab	0.502	919	—	0.093	44	0.093						0.070
Lower Chenab	1.753	1,790	1.035[e]	0.717	1,064							
Bahawal below MB I	0.165	220	—	0.165	219		See Bahawal Qaim above					
Bahawal below MB II	0.264	472	—	0.195	344							
Mailsi below SM	—	—	—	0.393	619	0.050	Shujaabad[g]	725	0.303	0.076	0.379	—
Sidhnai II	0.248	480	—	0.190	306							
Haveli I	0.106	184	—	0.063	53		Shorkot Kamalia[j]	426	0.222	0.072	0.294	0.066
Haveli II				0.075	133							
Abbasia Panjnad I	—	—	—	0.513	909	0.485	Abbasia Panjnad	1,623	0.716	0.162	0.878	0.100
Abbasia Panjnad II	0.942	1,582	0.160	0.688	1,180							
DG Khan	—	—	—	0.482	951							

Paharpur	—	—	—	0.080	174							
Thal	—	—	—	1.360	1,717							
Dadu North	0.118	367	—	0.082	157		Sukkur Right Bank[k]	820[i]	0.160	0.113	0.273	—
Rohri North	0.598	1,043	—	0.598	1,089		Rohri North	1,580[i]	0.451	0.147	0.598	—
Rohri South	0.528	886	—	0.528	945		Rohri South	1,500[i]	0.400	0.128	0.528	—
Khairpur West[f]	—	—	—	0.124	—	0.124	Khairpur West	—	—	—	—	0.124
Dadu South	0.027	93	0.276	—	—							
Dipalpur below B.S.	—	—	—	—	—		Dipalpur below B.S.[l]	850	0.362	0.249	0.611	—
Begari Sind	0.349	768	—	—	—	—	Begari Sind[l]	880	0.349	—	0.349	—
Wagah	—	—	—	—	—	—	Wagah[m]	95	0.047	—	0.047	—
Khairpur East	—	—	—	—	—	—	Khairpur East	—	—	—	—	0.330
Northwest Usable G. W.	0.155	309	—	—	—	—						
	7.459	11,942	1.809	8.098	12,516	0.959		11,498	4.183	1.622	5.805	1.028
			(0.867)[n]									

[a] Linear programming analysis is based on an implementation constraint of 20,000 four-cfs wells, including ongoing projects and one million acres for canal remodeling. The analysis also employs IACA's assessment of future private tubewell growth as well as the IACA projections of the attainable output responses per acre of CCA in the various project areas. Furthermore, this analysis accepts IACA's judgement that for technical reasons public tubewell development prior to 1975 should not be considered in Thal, D.G. Khan, Paharpur and in all Peshawar commands.

[b] IACA, Volume 2-A, p. 26.

[c] See Volume II.

[d] Including Mailsi above SM Link.

[e] 91% of the canal remodeling after 1975.

[f] Ongoing tubewell project.

[g] Including Mailsi below SM Link (.098) and Lower Bari Doab (.033).

[h] Including also Bahawal below MB I and II .429.

[i] Including tubewells required on remodeling after 1975.

[j] Including also Lower Chenab (0.120) and part of Lower Bari Doab (.031).

[k] Including Northwest Usable.

[l] Identified in IACA analysis as of priority between 1975–79, Volume 2-A, page 29.

[m] Replacement of Withdrawals under Indus Treaty.

[n] The drainage-cum-canal remodeling pilot projects proposed by IACA were not considered in this analysis.

private tubewell development. The Lower Rechna Development area did show an active private tubewell development and therefore its exclusion from the Action Program has to be viewed in the light of the modified comparative advantage of continued and *stimulated* private tubewell development in this area. The same explanation would seem to be applicable to the observed disagreement over the priority status of the Pakpattan above SM Link II command.

With regard to the allocation of the scarce canal remodeling activity, a comparison of priorities shows broad agreement on the allocation within the Northern Zone. In the Southern Zone, the allocation of 0.454 MA to the Khairpur commands was guided by the consultant's judgment that these commands represent "the most suitable area in the Region for the first attempt at the undoubtedly difficult task of remodeling" (IACA, Volume 19, Lower Indus Regional Development, p. 4). Since, the linear program data inputs could not capture the full range of the technical problems associated with remodeling projects, this judgment should override the economic priority derived for remodeling in Dadu South Command.

Thus, working exclusively with IACA data inputs as regards water budgets, private tubewell growth projections and projections of attainable output responses per acre cropped under alternative modes of water development, this analysis shows broad agreement with the project priorities recommended in the Action Program.

The one major difference in priority assessment, namely the priority for early public tubewell development in the Lower Chenab Development Area is the result of a different assessment of the comparative advantage of continued private tubewell development in this area over early public tubewell development. However, that part of the project area which shows an imminent need for a lowering of the groundwater table has been subsumed under the Shorkot-Kamalia Project recommended for early implementation.

Regarding the priorities for early canal remodeling, the priority lists for the Northern Zone are in agreement. In the Southern Zone, the allocation of scarce remodeling capacity to the Khairpur commands has been based on the judgment of LIP and IACA that this ongoing groundwater project offers a good opportunity to acquire the necessary experience with remodeling in the Southern Zone.

APPENDIX 4-1

THE STRUCTURE OF THE LINEAR PROGRAM

Introduction

The linear program formulated by the Study Group aims at deriving an optimal pattern of outlays for irrigated agriculture in the Indus Basin, differentiated by type, regional allocation, and timing of outlay. To generate such an optimal allocation of development expenditures, the linear program imposes specific resource constraints upon a mathematical model of irrigated agriculture in the Indus Basin and proceeds to find that pattern of outlays which maximizes the model's net-benefit function.

The model consists of a set of activities which describe the production potential of irrigated agriculture. Each of these activities applies to one of 54 canal commanded areas into which the program divides the CCA of the Indus Basin. Likewise, each of the activities applies to one of the two decision periods, 1965–75 and 1975–85, considered in the analysis. An activity can be operated at any level, provided that it does not violate the program's constraints. In the case of the "production activities" formulated for this model, the "level of operation" refers to the number of acres of CCA that are cultivated according to the particular mode of production described by the activity. Formally speaking, the program's solution will consist of a set of values for the levels of all activities which maximizes the net benefit function subject to the condition that all the program's constraints are satisfied. The program will also compute a shadow price on each constraint.

It will have been noted that the nontechnical presentation of this analysis refers to the activities defined in the program rather loosely as "projects." This term is justified to the extent that some of the activities formulated in the model make an attempt to capture the broad characteristics of alternative water investment opportunities as identified by the Special Study consultants. If there is any validity in the term "project," it would seem that the more an activity defined in the program describes the input requirements and output responses of a water investment *project,* the less realistic becomes the linearity assumption invoked in defense of the particular algorithm adopted in this analysis. In other words, to the extent that some of the activities are defined by *average* input requirements and *average* output responses of indivisible water investment projects, the use of integer programming would seem to be mandatory. However, it was possible to retain the *linear* programming technique by virtue of the fact that it tends to minimize the number of activities included in the solution. Due to this property of the linear programming algorithm, the solution of the program formulated for this analysis tended to approximate closely that of an integer approach in that, with very few exceptions, only "complete projects" were included. All through this analysis the Study Group employed the CEIR-LP 7090 Code.[1]

The following presentation will cover: the approach to the formulation of the activities, the specific definition of the various activities, the set of constraints which relates the activities to one another, and the objective function.

The Approach to the Formulation of the Activities

The alternative "projects" considered by the linear program represent alternative modes of improving the flow-irrigated acreage of each canal command through the construction of tubewells, tile drains, remodeling of canals, through increased supplies of regulated surface water and through combinations of these "measures." The decision whether and when to provide what combination of these improvements, i.e. whether and when to implement a specific public project, is viewed as a Government decision.

To formulate the linear program, the Indus Basin was divided into 54 regions which correspond broadly to the existing canal commands. (See Appendix 6.) For each of these 54 commanded areas alternative water development "projects" for part or all of the area have been formulated in a summary fashion.

[1] CEIR is a commercial computer-service organization which offers "software" services for operational research. LP 7090 refer to its linear programming code for an IBM 7090 computer.

The starting point for the formulation of "projects" under the linear program was the canal command analysis carried out by the Special Study consultants.[1] In brief, the linear program is based on IACA's cropwater requirements and their physical data relating to the respective canal command (CCA, canal size, groundwater quality zones), as well as their analysis of the achievable cropping intensity and the detailed water budgets for each of the canal commands under various conditions of development in the reference years 1975, 1985 and 2000.

The various conditions for which these water budgets were computed reflect different types of water investment and/or deviations from the historic levels of monthly surface water supplies. In detail the assumptions under which the alternative water budgets were computed are as follows:

Condition A: surface water is available limited only by the capacity of the canal system. No tubewells have been installed.

Condition B: same as Condition A, but surface supplies are fully integrated with groundwater pumping to balance recharge.

Condition C: all restraints in the canal system have been removed by remodeling in order to achieve the maximum agriculturally attainable intensity with a water budget which integrates the surface supplies with groundwater pumping to balance recharge.

Condition D: relates the cropping intensity attained in the base years to the historic pattern of monthly surface supplies and, if applicable, considers the extent to which these surface supplies have been and will be supplemented by supplies from private groundwater development.

Condition E: same as Condition A, but the exploitation of usable groundwater is projected to take place through private tubewells in a fashion which is strictly supplementary to surface supplies.

Depending upon the condition, each of these water budgets implies certain changes in the pattern and modes of present irrigation supplies, and it is possible to single out the five characteristic features of each alternative water budget in each of the canal commands. All features do not, of course, necessarily apply to every alternative water budget. In the following list feature (5), for example, automatically excludes features (1) through (4). Characteristics are:

1. the implicit required installed public tubewell capacity per acre of CCA;
2. the quantity of required scarce rabi surface water per acre of CCA;
3. the required extent of canal remodeling.
4. the required extent of horizontal drainage for areas in which this is judged to be a feasible mode of drainage; and
5. the projected extent of private tubewell development.

Given these alternative water budgets and given the corresponding numbers of cropped acres which each water budget is projected to be able to provide with adequate irrigation application, an estimate of the gross value of production per acre cropped was needed to project the output obtainable from providing a given water budget to a particular canal command. The projections of gross and net value of production per acre cropped which were employed in this analysis follow closely

[1] IACA, Volume 5, Annex 7, Chapter 6.

the projected cropping pattern and yield projections employed by IACA and set forth in the Comprehensive Report and in the respective IACA Project Reports.[1]

In particular with regard to the projection of yields, this analysis follows the assumption made by IACA that in the various canal commands the yield growth would be the *same* with and without public project coverage, provided that adequate water delta is applied and provided that the acreage is not waterlogged. Up to 1975, the IACA projections of GPV per cropped acre supplied with full delta make allowance for the fact that, in the absence of public project coverage or private tubewell supplies the cropping pattern would be influenced by the continued practice of underirrigation (with present varieties and with present levels of fertilizer inputs, a short-term advantage is gained through the extension of acreage by underirrigation). In the projections which have been used in this analysis IACA assumed that underirrigation will only be advantageous for minor crops. The IACA yield projections employed in this analysis, make further allowance for the yield-reducing effects of waterlogging. For the purpose of this analysis, these yield reductions have been computed following the IACA approach set forth in the Comprehensive Report.[2] Likewise, the projection of farm costs follows the approach set forth by IACA in the Comprehensive Report and in the respective project reports.[3]

All these IACA assumptions—including those which relate to the projection of farm costs—have been followed in the linear program. Combining the IACA assumptions with various combinations of the characteristic features of IACA water budgets, the Study Group worked out for its linear program a series of alternative courses of action (or potential projects).

For the evaluation of the comparative advantage of the alternative projects or courses of action listed below, it was necessary to include the period 1985–95 in the cost and benefit streams of the various "projects." Inclusion of this period allows for consideration of both the deferred cost and benefits which result from the choice of a particular project or course of action during the decision periods prior to 1985. In the determination of the final state of development which each commanded area is projected to achieve by 1995 the analysis follows the Special Study consultants.

The Activities in the Program

The various activities considered in the program are denoted by the following symbols and subscripts:

[1] IACA, Annex 9, pp. 68–71. The projections of gross value of production per acre cropped which were employed in this analysis are based on the detailed data generated by IACA in their Agricultural Production Projections undertaken by computer. This IACA data pertains largely to groundwater quality zones within canal commands and had to be aggregated for use in the linear program which employs the canal command as the area of analysis. By source and method of projection, this data used in the linear program is identical to that used by IACA in the individual project evaluations. However, a direct comparison of the data inputs of the linear program with the data inputs of the IACA project evaluations is not possible since the linear program data has taken account of the revaluation of the TDN output caused by IACA's upward revision of milk yields during a late stage of the Study. Given the advanced stage of the IACA project reports, this revision was incorporated into IACA's Comprehensive Report but could not be considered in the Project Reports. The same holds for the one project review appended to Volume II.

[2] Ibid. pp. 104-105.

[3] Ibid. pp. 115 ff.

The Production Activities. The production activities describing the alternative modes of developing flow-irrigated acreage in the Indus Basin are denoted by X with the following indices:

k: (1. . .54) denotes the canal command or divided canal command for which X has been defined.

t: (1, 2) indicates the time period for which the respective X has been defined. t=1, 1965–75; t=2, 1975–85.

p: (S1), (X1), (S2), (X2), (Y1), (Y2), (Z1), (Z2), (M1), denotes the type of agricultural and irrigation development to which the acreage of canal command k is subjected in period t; i.e., it denotes the type of project which is defined by the coefficients of X.
Using these indices the various production activities are denoted by X_{kpt}.
X_{kpt} is expressed in units of million acres of culturable CCA.

The following production activities have been defined for the program:

$X_{k(Y1)t}$. Projects to develop the usable groundwater through the installation of public tubewells beginning 1970. These tubewells are to be operated so as to integrate groundwater use up to balanced recharge with surface water supplies. The project formulation assumes that the latter supplies are limited only by the existing capacity of the distribution systems and that areas with a saline groundwater table at less than 10 feet below the surface in 1965 will subsequently be provided with drainage during the period 1975–85. Where technically feasible, horizontal drainage will be employed following the judgment of the Special Study consultants.

$X_{k(Z1)t}$. Projects which, beginning 1970, provide for public tubewell installation to pump the usable part of annual recharge and to integrate these tubewell supplies with surface water supplies which have been increased by canal remodeling between 1970–75 in order to achieve an average cropping intensity of 150 percent. The required increased drainage will be provided simultaneously with the provision of remodeling.

$X_{k(M1)t}$. Projects as outlined for $X_{k(Y1)t}$ but with the addition of subsequent canal remodeling during the 1975–85 period. Where required, drainage will be provided simultaneously with the provision of remodeling. The installed tubewell capacity would anticipate the remodeling scheduled to be undertaken about 5-10 years later.

$X_{k(Y2)t}$. Projects to develop the usable groundwater through the installation of public tubewells during 1975–85. These tubewells are to be operated so as to integrate groundwater use up to balanced recharge with surface water supplies. The latter supplies are limited only by the existing capacity of the distribution system. Areas with a saline groundwater table at less than 10 feet below the surface in 1965 will be provided with vertical drainage during the same period. Where technically feasible horizontal drainage will be employed following the judgment of the Special Study consultants.

$X_{k(Z2)t}$. Projects to provide for tubewell installation during 1975–85 to pump the usable part of annual recharge and to integrate these tubewell supplies with surface water supplies which have been increased through canal remodeling (simultaneously with the installation of wells) in order to achieve an average cropping intensity of 150 percent. Where required, drainage will be provided simultaneously with the provision of remodeling.

$X_{k(X1)t}$. An alternative course of action would be to undertake no Government investment in the respective commanded area during 1965–75. In this case, opportunity would be left for the exploitation of usable groundwater by private tubewells. In areas endowed with usable groundwater, private tubewell development is assumed to take place at the rate projected by the Special Study consultants. Acreage which does not benefit from private tubewell supplies will continue to be cultivated with the irrigation supplies which it received during the base years (e.g., 1963–65), and the production response of this acreage has been projected on the assumption that underirrigation of minor crops will be continued up to 1975. Likewise, where waterlogging is a problem, the production response of acreage which benefits neither from the drainage effects of public or private wells has been projected so as to reflect the yield-reducing effects of a high water table. For this alternative course of action the cropped acreage has been projected by relating the cropping intensity attained in the base years to the historic pattern of monthly surface supplies and, if applicable, by considering the extent to which these surface supplies have been and will be supplemented by supplies from private tubewells.

$X_{k(S1)t}$. An alternative course would be to provide during 1970–75 surface water supplies, including rabi supplies in excess of historic withdrawals, up to the limits of the existing canal capacity. This course of action is limited to those commanded areas where drainage needs allow the introduction of increased surface water supplies without the danger of creating or aggravating the problems of waterlogging. $X_{k(S)t}$ represents a variant of $X_{k(X)t}$ in that it also assumes continued private tubewell development. However, private tubewell supplies are assumed to be strictly supplementary to the increased surface water supplies.

$X_{k(X2)t}$. For the period t=2 (1975–85), an alternative course of action would be to undertake no Government investment, in which case the development of this acreage is projected to continue along the lines projected for the respective course of action outlined under $X_{k(X1)t}$ above.

$X_{k(S2)t}$. For the period t=2 (1975–85), an alternative course of action would be to provide increased surface water supplies, drainage needs permitting. This course of action represents a variant of $X_{k(X2)t}$ in that it also allows for private tubewell supplies to supplement the increased surface water supplies.

The Public Tubewell Investment Activities. These activities describe the cost and benefits (in terms of irrigation supplies) of installing and operating public four-cfs tubewells in canal command k during the period t. The subscript τ = (1,2) is utilized to denote the point in time at which the tubewell was assumed to be installed; $\tau = 1$ refers to 1971; $\tau = 2$ refers to 1980.

These investment activities are denoted by the symbol $W_{k\tau t}$ and are expressed in units of 4 cfs equivalent public tubewells.[1]

The Constraints Specified in the Program

Constraints Attached to Each Canal Command.

1. The area constraint:
(row name in matrix: kAR1, kAR2)

$$\sum_{p} X_{kpt} = A_k \quad t = 1,2$$

The area constraint requires in each time period t in canal command k the sum of all acreage covered by the various project types p to be equal to the CCA of the respective canal command. It should be noted that this constraint has been deliberately formulated as an equality in order to prevent the formulation of an optimal solution which allows for slack in this constraint, i.e., a solution which recommends the politically unacceptable withdrawal of hitherto cultivated flow-irrigated acreage from production.

2. The public tubewell investment constraint:
(row name in matrix: kWA1, kWA2)

$$\sum_{p} \eta_{kpt} X_{kpt} \leqslant \sum_{\tau} W_{k\tau t} \qquad t = 1,2$$

η_{kpt} is defined as the tubewell pumping capacity required per acre of CCA covered by project type p in period t. The required tubewell pumping capacity is expressed in units of 4-cfs wells per acre of CCA.

The public tubewell investment constraint requires that the public tubewell pumping capacity available in canal command k in period t be no less than that required by the type of project coverage provided for the acreage in canal command k during the period t.

3. It is also required that:

$$\sum_{p} X_{kpt} = \sum_{p} X_{kpt-1} \qquad \text{for} \qquad p = (Y1), (Z1), (M1).$$

This requirement ensures that once a certain type of project coverage has been provided to a given acreage this Government decision cannot be reversed in the subsequent period and the scheduled improvements which formed part of the project have to be completed.

Basin Wide Constraints

1. The gross production value constraint:
(row name in matrix: 70 PV1, 70 PV2)

$$\sum_{kp} \pi_{kpt} X_{kpt} \geqslant T_t \qquad t = 1,2$$

π_{kpt} expresses the gross production value (GPV) which is projected to be attained per acre of CCA covered by project type p in the last year of the period t. This constraint makes it possible to set a lower bound to the

[1] One two-cfs well = 0.75 four-cfs wells
One three-cfs well = 0.875 four-cfs wells

aggregate output response of the water investment programs (T_t) considered in the search for the optimal program.

2. The foreign exchange constraint:
(row name in matrix: ØFXC1, ØFXC2)

$$\sum_{kp} \Omega^x{}_{kpt} X_{kpt} + \sum_{k} \Omega^w{}_{k\tau t} \cdot W_{k\tau t} \leqslant F_t \qquad t = 1,2$$

Ω^x_{kpt} is expressed in US$ per acre of CCA. It states the direct, annual import component of farm costs, private tubewell costs and project operating and investment costs which are associated with providing a certain type of project coverage in canal command k during period t.

$\Omega^w_{k\tau t}$ expressed the direct, annual average import requirement associated with the installation and operation of public tubewells in canal command k. The coefficient is expressed in US$ per four-cfs well.

This constraint makes it possible to set an upper bound to the foreign exchange requirements of any water investment program considered in the search for the optimal program. More specifically, the constraint requires that the annual direct import requirements generated by the implementation and operation of the various projects should not exceed a certain assumed foreign exchange availability F_t in the reference years 1975 and 1985.

3. The public tubewell implementation constraint:
(row name in matrix: 70 WC1, 70 WC2)

$$\sum_{k} W_{k\tau t} \leqslant P_t \qquad \begin{array}{l} \tau = 1,2 \\ t = 1,2 \end{array}$$

This constraint sets an upper bound to the number of public tubewells (four-cfs equivalent wells) (P) which can be installed during period t.

4. The canal remodeling implementation constraint:
(row name in matrix: 70 CR1, 70 CR2)

$$\sum_{kp} \Phi_{kpt} X_{kpt} \leqslant C_t \qquad t = 1,2$$

Φ_{kpt} expresses the canal remodeling requirements of an acre of CCA in canal command k for a given type of project coverage. It is expressed in acres of CCA to be served by remodeled canals in proportion to the total CCA of the canal command. The constraint sets an upper bound to the size of the canal remodeling program (C_t) in terms of the acres of CCA which can, in any period, be served by newly-remodeled canals.

5. The extended rabi surface water constraint:
(row name in matrix: ERSW1, ERSW2)

$$\sum_{kp} \beta_{kpt} X_{kpt} \leqslant R_t \qquad t = 1,2$$

β_{kpt} expresses the extended rabi surface water requirements of an acre of CCA covered by project type p in canal command k during time period t. The coefficient is expressed in acre feet per acre of CCA and pertains to the irrigation requirements projected for the last year of the respective time period. The rabi surface water component of the watercourse requirements has been scaled up by canal losses and river and link canal losses to the equivalent river station requirement. R_t represents the sum of the surface water availabilities at the rim stations (Marala H.W., Mangla, Tarbela and Attock (Kabul)) which have been considered as additive without further transformations. For the purpose of the linear program analysis the extended rabi period has been considered to comprise the six-month period from November to April.

6. The public investment fund constraint:
(row name in matrix: FUND 1)

$$\sum_{kp} \lambda^{x}_{kpt} X_{kpt} + \sum_{k} \lambda^{w}_{k\tau t} W_{k\tau t} \leqslant P_t \qquad \text{for} \qquad t = 1$$

λ^{x}_{kpt} states the required public investment outlays which are associated with providing a certain type of project coverage in canal command k during period t. The coefficient is expressed in Rs. per acre of CCA.

$\lambda^{w}_{k\tau t}$ expresses the required public investment outlay per public four-cfs well. This constraint makes it possible to set an upper bound to the public investment outlays (P_t) required by alternative water investment programs during 1965–75.

The Objective Function

The inclusion of this row allows for the comparison of the desirability of different feasible programs. That is, if there are a number of feasible programs proposed to the linear program, it will compute the present value of the net benefit stream generated by each of these feasible programs and will indicate as most desirable the one with the largest net present value.

Each activity defined in the program enters this matrix row (row name: NTBEN) with its respective valuation coefficient which describes the present worth of the net benefit stream generated by cultivating the respective irrigated acreage according to the mode of cultivation X_{kpt}. In the case of a public tubewell project, this net benefit stream would also have to consider the valuation coefficient

$$\delta^{w}_{k\tau t} \qquad \text{of the} \qquad W_{k\tau t}$$

activities which describes the present worth of the expenditure stream associated with the installation and operation of public tubewells in the respective canal command k.

$$\sum_{kt} \delta^{x}_{kpt} X_{kpt} + \sum_{kt} \delta^{w}_{k\tau t} W_{k\tau t} = \text{Maximum}$$

The valuation coefficient δ^{x}_{kpt} is expressed in rupees present worth at 8 percent as of 1965. They are deduced by going through the following steps: for each activity X_{kpt} a projection is made of the time path of cropping intensities and yields per acre for each of the principal crops. The time paths of physical outputs are multiplied by constant prices to obtain a corresponding time path of gross production value per acre of CCA cultivated according to the mode of production summarized in the coefficients of activity X_{kpt}. These time paths are then discounted back to 1965 using an 8 percent rate of discount. Associated farm operating, project operating, investment and maintenance cost other than those pertaining to public tubewell investment are similarly estimated over the years and discounted back to 1965. The valuation coefficient states the present worth of the difference between the gross benefit and the cost streams generated by cultivating an acre of CCA in canal command k according to activity X_{kpt}.

In the computation of the respective valuation coefficients, we assumed that the conversion of acreage from one mode of cultivation to another occurs in constant proportions of the canal command's CCA between reference years. For instance, activity $X_{k(Y1)t}$ assumes project coverage to occur between 1970 and 1975; therefore it was assumed that between 1970 and 1975 annually 20 percent of the project CCA is converted from the benefit and cost stream association with $X_{k(X1)t}$ to those associated with $X_{k(Y1)t}$.[1]

APPENDIX 4-2

INTERPRETATION OF THE VALUATION OF FOREIGN EXCHANGE DERIVED IN THE LINEAR PROGRAM

The increase in aggregate net benefits which is shown as attainable via a marginal increase in foreign exchange availability must properly be assigned to increased foreign exchange availability in years both before and after the reference year. If the foreign exchange availability were increased in 1975 but not in the preceding years, the increase in net benefits computed by the program would not be attainable. It was assumed in the formulation of the model that the conversion of acreage in any canal command from one mode of production to another proceeds in annual increments of 10 percent of the CCA. This means that the increase in the average foreign exchange use-coefficient, due to a change to a more foreign exchange using mode of production, occurs equally gradually over the 10-year period.

In other words, a change in the 1975 foreign exchange availability by one unit actually presupposes a total change in foreign exchange availability which is distributed over the years before and after 1975 equal to the value of the following integral:

$$\int_0^{10} \frac{at}{10} e^{-rt}\, dt + e^{-10r} \int_0^{10} a \frac{(1-t)}{10} e^{-rt}\, dt$$

[1] For this conversion path, the present worth of the gross benefits stream, farm cost and project operating cost streams was computed as follows:

$$\int_0^5 \left(c'_0 + \frac{c'_1 - c_0}{5} t\right) e^{-rt}\, dt + e^{-5r} \int_0^5 \left[\left(1 - \frac{t}{5}\right)\left(c'_1 + \frac{c'_2 - c'_1}{5} t\right)\right.$$

$$\left. + \frac{t}{5}\left(c'_1 + \frac{c_2 - c'_1}{5} t\right)\right] e^{-rt}\, dt + e^{-10r} \int_0^{10} \left(c_2 + \frac{c_3 - c_2}{5} t\right) e^{-rt}\, dt$$

$$+ e^{-20r} \int_0^{10} \left(c_3 + \frac{c_4 - c_3}{10} t\right) e^{-rt}$$

The symbol c_m denotes the benefit level or expenditure level generated or required per acre of CCA by the respective activity in the reference years m = (0 . . . 4). Where m = 0 (1965), m = 1 (1970), m = 2 (1975), m = 3 (1985), m = 4 (1995).
c_m denotes the benefit or expenditure level generated or required by the preceding mode of cultivation, in this case $X_{k(x1)1}$.

Where a represents the change in 1975 foreign exchange availability, t represents the respective point in time, r stands for the discount rate of 8 percent and e equals 2.7183. The value of the integral can be computed as 4.738[a] which means that the change in program net benefits attainable from a change of a in 1975 foreign exchange availability should be properly related to 4.738 times the change.

Similarly, the increase in net benefits computed by the program for a marginal increase in the 1985 foreign exchange availability has to be properly related to the value of the following integral:

$$e^{-10r}\int_0^{10} \frac{at}{10} e^{-rt}\, dt + e^{-20r}\int_0^{10} a\, e^{-rt}\, dt$$

which is equal to 2.7326a. In other words, a change in the 1985 foreign exchange availability by Rs. 1 actually represents a total change in foreign exchange availability distributed over the years before and after 1985 which has a present worth of Rs. 2.73a.

The following conversion path has been assumed for the remaining activities:

$$X_{k(Z1)1} \text{ and } X_{k(M1)1} \quad : \quad 1970\text{–}1975$$
$$X_{k(Y2)1} \text{ and } X_{k(Z2)2} \quad : \quad 1975\text{–}1985$$

The valuation coefficient of the W-activities is expressed in rupees present worth at 8 percent as of 1965. These coefficients describe the present worth of the cost stream generated by the installation of one public four-cfs well either during the period 1970–75 or during the period 1975–85, plus the cost of operating and replacing the tubewell over the period up to 1995. The cost estimates employed in this analysis follow those set forth by IACA in Volume 5, Annexure 7, Chapter 5.

APPENDIX 4-3

INTERPRETATION OF THE VALUATION OF RABI SURFACE WATER DERIVED IN THE LINEAR PROGRAM

The valuation of rabi surface water derived in the solution of the linear program measures the effect of a change by one acre-foot in the availability of regulated surface water on the present value of the aggregate net benefits of the optimal investment program. Literally construed, the program tells us that increased availability of regulated surface water in 1985 by one acre-foot at the rim station would allow for a change in the total input mix of the program which would allow a certain increase in the present worth of the aggregate net benefits. However, to give this information an economic interpretation, certain aspects of the model formulation have to be taken into account. As the model is set up, the only years mentioned explicitly are 1975 and 1985. However, other years are using inputs and contributing benefits as well and have to be considered in the interpretation of the accounting prices. Therefore it is necessary to consider the reference years as representative for the preceding 10 years, which means that 1985 is to be considered representative for all years after 1975 up to 1985. This means that the extra rabi surface water has to be made available beginning from 1975 in order to obtain the extra benefits which formally in the program are related to the increase in the 1985 rabi surface water availability. In other words, the increase in net benefits represents the marginal agricultural value of one additional acre-foot of storage capacity made available by 1975.

APPENDIX 4-4

INTERPRETATION OF THE VALUATION OF PUBLIC OUTLAYS FOR WATER INVESTMENT DERIVED IN THE LINEAR PROGRAM

The valuation of public outlays for water investment (including investment in electric distribution lines) derived in the solution of the linear program measures the effect of an increase in the size of the water investment budget for the period 1965 to 1975 by one rupee on the present value of the aggregate net benefits of the optimal investment program. Literally construed, the program tells us that the outlay of one additional Rupee of public funds during 1965–75 would allow for a change in the import mix of the program which would generate a certain increase in the present worth of the aggregate net benefits.

To the extent that the increase in net benefits is expressed in terms of present worth at eight percent as of 1965, it is necessary to express the increase in public investment outlays in the same form. Since the public investment fund constraint covers a 10-year period, it is necessary to make an arbitrary allocation of this incremented public outlay somewhere within this period. For the purpose of this interpretation of the valuation of public outlays, we have allocated it to 1970, which at a discount rate of eight percent gives an outlay of Rs. 1a present worth of Rs. 0.681 as of 1965.

If we want to express the valuation of the marginal rupee of public investment outlays in terms of a marginal benefit/cost ratio, it is further necessary to consider that in the program net benefits represent the agricultural gross production value minus farm and project operating costs, *as well as capital cost.* If we define our benefit/cost ratio as the ratio of gross production value minus farm and project operating costs over the capital costs, we have to increase the incremented net benefits computed by the program by the present worth of the public investment outlay to which we attribute this increment in net benefits.

APPENDIX TABLE 4-5

The Area Units Used in the Linear Programming Analysis

For the purpose of this analysis, CCA was divided into the following 54 area units. The names used in the listing pertain to the 61 canal commands used in the analysis of IACA.

Canal Command	CCA million acres
1. Dipalpur above BS Link	0.372
2. Ravi Syphon Dipalpur Link	0.595[a]
3. Upper Chenab I and II	1.445
4. Bahawal above MB, Qaim	0.093
5. Fordwah and E. Sadiqia I	0.975
6. Fordwah and E. Sadiqia II	0.387
7. Pakpattan above SM I	0.607
8. Pakpattan above SM II	0.347[b]
9. Dipalpur below BS	0.611
10. Lower Bari Doab	1.482[c]
11. Lower Chenab I	1.753[d]
12. Lower Chenab II	0.148
13. LJC I	1.285
14. LJC II	0.215
15. UJC I, II, II	0.543
16. MR Link	0.105
17. Bahawal below MB I	0.275
18. Bahawal below MB II	0.321
19. Mailsi below SM	0.677
20. Pakpattan below SM	0.319
21. Sidhnai I	0.493
22. Sidhnai II	0.261
23. Haveli I and II	0.106[e]
24. Ranjpur	0.344
25. Abbasia Panjnad I	0.513
26. Abbasia Panjnad II	0.942
27. DG Khan	0.872
28. Muzaffargarh	0.656
29. Pakarpur	0.104
30. Thal	1.641
31. Upper Swat	0.276
32. Lower Swat	0.169
33. Kabul River	0.123
34. Warsak	0.119
35. Ghotki	0.513
36. Begari Sind Usable	0.349
37. Begari Sind Saline	0.344
38. Desert ind. Pat	0.382
39. Northwest Usable	0.155
40. Northwest Saline	0.220
41. Northwest Khirtar	0.258
42. Rice	0.337
43. Dadu North	0.118
44. Dadu South	0.276
45. Khairpur West	0.252
46. Khairpur East	0.330
47. Rohri North	1.075
48. Nara Pumps	0.084
49. Rohri South	1.405
50. E. Nava South	1.559
51. Kalri Bagar Feeder, NP	0.159
52. KB-Ochito & Pumps	0.115
53. Pinyari-Fuleli	0.897
54. Gaja-Tando Bago	0.152

[a] The Wagah area comprising 0.047 MA was not considered in this analysis.
[b] Includes Mailsi above SM Link.
[c] Excludes the drainage cum canal remodeling pilot project proposed for 0.093 MA.
[d] Excludes the SCARP I area which comprises 1.080 MA.
[e] Excludes the drainage cum canal remodeling pilot project proposed for 0.037 MA.

APPENDIX TABLE 4-6

ESTIMATED TOTAL SURFACE WATER AVAILABILITY DURING NOVEMBER–APRIL IN THE TEST YEARS 1975 AND 1985

In the analysis, the total availability of surface water during the months November to April was computed as follows:

1. Availability in Reference Year 1975	
Mean Indus Flow at Tarbela, November-April	8.62 MAF
Mean Jhelum Flow at Mangla, November-April	6.42 MAF
Mean Chenab Flow at Marala, November-April	4.59 MAF
Mean Kabul Flow above Attock, November-April	6.34 MAF[a]
Mangla Reservoir[b c]	4.00 MAF
Chasma	0.51 MAF
	30.48 MAF[d]
2. Availability in Reference Year 1985	
Mean Indus Flow at Tarbela, November-April	8.62 MAF
Mean Jhelum Flow at Mangla, November-April	6.42 MAF
Mean Chenab Flow at Marala, November-April	4.59 MAF
Mean Kabul Flow above Attock, November-April	6.34 MAF[a]
Mangla Reservoir[b c]	3.85 MAF
Chasma	0.51 MAF
Tarbela[e f]	7.05 MAF
Sehwan-Manchar[g]	2.10 MAF
	39.48 MAF[h]

[a] Mean Kabul flow above Attock plus historic withdrawals of the Peshawar commands.

[b] Mangla, live storage in 1975, drawdown level 1040: 5.20 MAF
Mangla, live storage in 1985, drawdown level 1040: 5.00 MAF

[c] Assumes that 77% of Mangla's live storage will be released during the period November to April.

[d] For use in the model this total has been reduced by 1.13 MAF representing the part of the total rabi surface water availability which would be used in SCARP I (0.76 MAF) and in the Bari Doab and Rechna Doab Drainage and Canal Remodeling Pilot Projects (0.37 MAF).

[e] Tarbela, live storage in 1985, drawdown level 1332: 7.40 MAF

[f] Assumes that 95% of Tarbela's live storage will be released during the period November to April.

[g] 1984/85 storage available during scarce water period from Sehwan Manchar equals: 1.8 MAF.
However, all loss factors built into the surface water constraint of the linear program assume supplies to originate from either Tarbela or Mangla and therefore understate the watercourse availabilities attainable from Sehwan Manchar by about 16 percent. To account for this fact we treat the storage supply from Sehwan Manchar as equivalent to: 2.10 MAF.

[h] For use in the model this total has been reduced by 1.51 MAF representing the part of the total rabi surface water availability which would be used in SCARP I (1.13 MAF) and in the Bari Doab and Rechna Doab Drainage and Canal Remodeling Pilot Projects (0.38 MAF).

APPENDIX TABLE 4-7

NUMBER OF PRIVATE TUBEWELLS PROJECTED BY IACA TO BE INSTALLED IN THE ABSENCE OF PUBLIC GROUNDWATER DEVELOPMENT

Command	1965	1970	1975	1985
Dipalpur AB.	860	1,840	2,470	3,120
R.D. Link Int.	1,180	2,550	3,440	4,360
U.C.C. 1.	3,130	4,310	5,060	5,930
U.C.C. 2.	1,610	3,230	4,050	4,870
Bahawal AB.	40	110	170	230
Qaim	40	90	140	190
Mailsi AB.	40	80	100	130
Fordwah 1.	60	140	208	280
Fordwah 2.	290	680	1,010	1,370
Pak Above I.	1,420	2,930	3,896	4,910
Pak Above II.	810	1,670	2,210	2,790
Dip Below	1,470	3,050	4,060	5,120
LBDC Ins.	3,590	7,410	9,870	12,450
LCC I Less Scarp I.	3,430	5,920	7,500	9,200
LCC II.	280	660	890	1,130
LJC I.	340	1,380	2,650	4,130
LJC II.	70	300	570	890
UJC I.	230	680	1,080	1,500
UJC II.	70	210	330	460
UJC III.	130	400	630	870
MR Link Int.	990	1,170	1,300	1,440
Bahawal Bel I.	140	360	550	760
Bahawal Bel II.	220	580	880	1,210
Mailsi Bel	1,230	2,520	3,330	4,200
Pak Bel	430	890	1,180	1,480
Sidhnai I.	1,170	2,380	3,150	3,970
Sidhnai II.	610	1,250	1,660	2,090
Haveli I.	20	70	100	140
Haveli II.	10	170	250	340
Rangpur.	190	610	1,020	1,500
Panjnad I.	40	130	220	310
Panjnad II.	570	1,860	3,010	4,260
DG Khan.	280	780	1,310	1,990
M'Garh.	210	760	1,560	2,560
Thal.	450	1,500	3,000	4,900
Lower Swat.	10	30	80	217
Kabul River.	—	10	20	50
SIND				
Ghotki	230	790	1,300	1,850
Begari Sind US.	90	230	520	980
North West US.	10	50	150	390
Dadu North	20	60	160	320
Dadu South	10	10	40	70
Rohri North	100	300	790	1,600
Rohri South	170	560	1,150	1,900

APPENDIX 4-8

METHOD OF CALCULATION OF CANAL ENLARGEMENT COSTS

The Method of Calculation involves the following data and assumptions:

1. CCA of canal command unit used in linear program.
2. CCA affected by canal capacity constraint ranges between zero and the total CCA in (1) and is derived from examination of the separate groundwater quality zones of each of the IACA divided canal command units.
3. Percentage capacity increase on affected CCA is consistent with the requirements for canal enlargement shown in Table 8.8 of IACA Annexure 7 but is related to CCA affected by capacity constraint instead of to total CCA.
4. Unit cost in Rs./acre of enlarging distributory and minor canals, including remodeling of outlets, is taken from the graph in Figure 7.14 of IACA Annexure 7 for the percentage increases derived in (3).
5. Total cost of enlarging distributories and minors = (2) × (4).
6. Canal command factor is used to derive the total enlargement costs within a canal command from the distributory and minor costs and is a measure of the relative amount of work involved in the main and branch canal enlargement. The general cost of main and branch canal enlargement is taken as 75 percent of the distributory and minor cost. (This is more than indicated in IACA Annexure 7, and represents 60 percent for main and branch canals plus 10 percent general contingency on the entire canal command cost.)

   The allowance for main and branch canals is reduced to one third at 25 percent on Thal and several of the Lower Indus canals where there is already spare capacity in the main canal design and where enlargement can be achieved by excavation without any structural work.

   The work will generally be much less where only a small amount of enlargement is required and the allowance for main and branch canals is halved to 37 percent where enlargement is 10 percent or less of the existing capacity.

   Where only part of a canal command is affected by the capacity constraint, the requirement for main and branch canal enlargement may be higher as many miles of canal may serve effectively as links to the affected areas. In such cases the allowance for main and branch canals is doubled to 150 percent but not exceeding 75 percent on the total canal command CCA. The higher cost is not applied if the enlargement for the total command is less than 10 percent of the existing capacity.

   IACA have stated (Page 53 of Annexure 7) that enlargement costs would be higher in the Lower Indus region and therefore costs are increased by 30 percent for all Lower Indus Commands. Costs are also increased in the Vale of Peshawar where particularly difficult construction problems would be encountered.

The canal command factors are summarized below:

	Northern Zone	Lower Indus
Standard factor	1.75	2.28
Spare capacity in main and branch	1.25	1.63
Less than 10% enlargement	1.37	1.78
Part only of command affected	1.75 to 2.50	2.28 to 3.25

7. Enlargement cost for canal command = (5) × (6).
8. Link requirements apply to a number of Punjab commands. Miles of link canal are measured, roughly and on the high side, from the map. Capacity of additional link requirement in cusecs is derived from the canal command requirement for enlargement.
9. Link requirement in cusec miles = miles of link to serve the area x cusecs of required enlargement.
10. Link canal cost = 375 × (9). Rs. 375 per cusec mile is derived from an approximate cost of Rs. 250 per cusec mile on the TSMB Link plus a 50 percent allowance for river control works.
11. Total enlargement cost = (7) + (10).

SUPPLEMENTAL PAPER V

Private Tubewell Electrification

Existing Numbers of Electrified Wells and Recent Growth

In the past, WAPDA has not maintained separate statistics on private tubewells. As a result, the surge of private tubewell development was not recognized until some time after it had gotten under way. There is also considerable uncertainty about the role that private tubewells are playing currently in the demand for electricity. For instance there are several different estimates of the number of electrified wells in existence in 1965, the year adopted as the base year for much of the work in the Study. IACA adopted a figure of 9,000 for the number of electrified private wells in existence in 1965. The survey which has been carried out annually in recent years by the Pakistan Institute of Development Economics (PIDE), in conjunction with the West Pakistan Department of Agriculture, indicates a figure of about 9,800 electrified private wells in existence in August-September 1965. The power consultants Stone & Webster, however, used WAPDA statistics on the number of agricultural customers (kept separately and supposed to represent the number of bonafide agricultural customers using tubewells or lift pumps for irrigation purposes, because these are the ones entitled to the subsidized rate of eight paisa per kwh). By subtracting out the number of public tubewells (about 3,600 as of June 30, 1965, including the 1,400 Rasul wells of the Irrigation Department) they estimated that there were about 13,000 electrified private wells in operation as of June 30, 1965.

It is hard to choose among these estimates. The S&W figure is probably on the high side because some of the agricultural customers are undoubtedly owners of lift wells. But there is no evidence to suggest that the number of lift wells in existence is sufficient to account for a large portion of the difference between the estimate based on the PIDE surveys and that based on WAPDA statistics. Assuming no double counting in WAPDA figures, the conclusion must be that either the PIDE figures are a serious underestimate or that many of the wells receiving power at the subsidized rate are not really agricultural wells but wells for village water supply.

It may well be that the PIDE surveys underestimate the number of private wells in existence. The survey indicated a total of about 31,900 private wells installed by 1965, including an estimated 5,000 outside the canal commanded areas and about 700 in the Sind. Subsequent studies by Tipton and Kalmbach in the Bari Doab indicate the existence of a substantially larger number of wells there than suggested by the PIDE study. Taking account of the study, the Study Group has adopted an estimate of about 34,000 private wells installed by 1965 (Volume II, Chapter 4).

The picture with regard to the growth of electrified private tubewells is also quite unclear. Table 5-1 compares figures derived from WAPDA statistics with the results of the PIDE surveys. The WAPDA figures are supposed to relate to June 30 of the year in question, and the PIDE figures to August-September of each year. The WAPDA figures suggest an increase in the number of electrified private wells in existence, between mid-1964 and mid-1966, of about 8,000 (allowing for some 250 of the agricultural customers added being lift-well operators) while the PIDE figures suggest an increase of about 6,300 over the same period. Despite the inconsistencies among the figures several conclusions seem to be clear.

1. The number of private tubewells installed has been increasing extremely rapidly. The Study Group estimates in Volume II that about 25,000 private tubewells were installed during the Second Plan period.
2. The pace of installation of private tubewells continued to increase, from about 7000 in 1964/65 to over 8000 in 1965/66 according to the PIDE figures. But a few of the wells installed, perhaps 500, may be replacements.
3. Less than half the private tubewells in existence are electrified.
4. The proportion of private tubewells which is electrified is increasing—from about 26 percent of total wells installed by 1964 to about 32 percent by 1966, according to PIDE figures. WAPDA numbers of electrified private wells with PIDE numbers for all wells imply that the electrified share rose from 40 percent to 45 percent over the same period.
5. Absence of electrification does not appear to be a very serious bar to the installation of a private tubewell, since about half the private wells installed in 1964–66 were not electric and the majority of those currently in existence are not electric.

Relative Price to Farmers of Water Pumped by Diesel and Electric Wells

It is not surprising that the proportion of wells electrified has been rising in recent years: it is much cheaper for the farmer to buy and operate an electric motor than a diesel engine and there has been substantial pressure on WAPDA to extend electrification for private tubewells. The type and size of engine/motor bought by private tubewell owners varies greatly, but typical sizes and costs seem

TABLE 5-1
Growth of Electrified Private Tubewells
(numbers in existence)

	1960	1961	1962	1963	1964	1965	1966
WAPDA Accounts							
Agricultural Customers	3,300	4,663	7,997	9,957	13,519	16,712	21,914
less SCARP Wells (estimate)	—	300	1,230	2,043	2,206	2,212	2,342
Irrigation Department	1,600	1,660	1,660	1,400	1,400	1,400	1,400
Private	1,700	2,703	5,107	6,514	9,913	13,100	18,172
PIDE Survey of Private Wells							
Electric Wells					6,590	9,800	12,940
Total Wells					25,000	31,900	40,100

to be an 8-10-kw electric motor costing about Rs. 2,500 and a 16-hp diesel engine costing about double this amount. Moreover diesel fuel is heavily taxed. It can be estimated that, at current prices to the farmer for diesel fuel and for electricity, and taking account of the relative capital and maintenance costs for diesel and electric wells, as borne by the farmer, an acre-foot pumped by a diesel well costs him about twice as much as does an acre-foot pumped by a well with an electric motor —about Rs. 26 against Rs. 13. Thus, at current prices there is a very strong incentive to electrify a private tubewell.

This incentive price structure has grown up partly because it was found, when the private tubewell movement among the farmers was first noticed, that tubewells had sprung up particularly rapidly in areas reasonably close to transmission lines or covered by existing distribution networks. The availability of electricity was, in other words, a strong incentive to installation of a private tubewell; and to help stimulate the spread of private tubewells, it was decided to subsidize the price of electricity. Considering that at least 30-40 percent of the existing private tubewells are electric, whereas a far smaller proportion of the areas with groundwater characteristics suitable for private tubewell development have power lines near at hand, it is quite clear that private wells are much more dense in electrified areas than in nonelectrified areas. Nevertheless, the substantial growth of diesel wells that has occurred also indicates that the profitability of wells is sufficient to make it worthwhile to bear the much heavier costs involved in a diesel operation. It is, moreover, very doubtful whether the subsidy on electricity sold to farmers can have had much stimulative effect since, even if tubewell owners were charged the full cost of the power they consume (estimated by S&W, on analogy with the price for small industrial loads, at about 13 paisa per kwh) the cost per acre-foot, on a comparable basis to the figures cited above, would be only about Rs. 17. This is still 35 percent beneath the cost of an acre-foot pumped by a diesel well.

Expansion of the Electricity Distribution Network

Much more important than the price of electricity in promoting electrification of wells has been the sheer physical availability of electric power. WAPDA has not been able to keep up with the growth of demand for electrification and there has continued to be a large backlog of customers awaiting connection. Figures provided by WAPDA indicate that, between July 1, 1960 and June 30, 1965 (the Second Plan period), the achievement in terms of expansion of the distribution system and new connections was impressive; nevertheless, concentration of effort on new connections led to some neglect of maintenance on the existing parts of the system, and the expansion was not sufficient to keep up with demand. WAPDA's customers increased about 120 percent over the Second Plan period from 312,000 to 688,000; the number of electrified villages in the Province more than doubled from about 900 in 1960 to nearly 1900 in 1965; nearly 15,000 miles of distribution line (9,100 miles of 11 kv line and 5,600 miles of 400-volt line) were built. A large proportion of the rural electrification was in connection with the extensive SCARP I project. Some portion of the new customers added to the WAPDA system were simply taken over from small municipal utilities amalgamated with the WAPDA system and some of the distribution line achievement may represent pre-existing lines taken over by WAPDA; nevertheless the achievement was clearly substantial.

Stone & Webster found that their load forecast implied such substantial increase in the number of customers on the WAPDA system over the next 10 years that they were doubtful whether WAPDA would in fact be able to make sufficient connections. Leaving aside new industrial and bulk consumers of power, the amount of new distribution line required to service additional general (i.e. residential and commercial) and agricultural customers, as assessed by S&W, is given in Table 5-2. S&W adjusted downwards these total estimates of distribution line requirements to eliminate any double counting involved and they thus reached net figures of 20,700 miles of line required for the Third Plan period and 35,600 miles for the Fourth Plan period. S&W felt these goals, particularly that for the Third Plan period, would be unattainable; it was their view that a total of 16,000 miles of new distribution lines constructed during the Third Plan would represent a maximum effort. They anticipated therefore some curtailment of the tubewell program and village electrification programs.

Relative Economic Costs of Water Pumped by Diesel and Electric Wells

Quite apart from the capability of WAPDA to erect distribution lines and connect private tubewells, questions have been raised as to whether electrification is not really more costly to Pakistan than the continued installation of diesel engines to power private tubewells—despite the present structure of financial prices which, as indicated, is heavily biased towards encouraging electrification. Such a variety of economic costs, whose precise magnitude is quite uncertain, and so many variables apart from economic costs, would enter into formulation of a correct answer to this question that it is impossible to be definitive. It is clear that no single answer could be of general validity, given the wide variety of specific circumstances relating to each individual tubewell site. Nevertheless, it is clear in general terms

TABLE 5-2
Additional Distribution Line Required to Connect New Customers, 1965–75

	1965–70	1970–75
Numbers of New Customers		
General	477,000	671,000
Public Wells—Fresh	8,400	12,950
Saline	150	4,150
Private Wells—Special[a]	6,000	8,800
Routine[b]	8,900	13,100
Miles of Distribution Line (400 volt and 11 kv) Required		
For General (50 customers/mile)[c]	9,500	16,800
Wells: Public—Fresh (1.3 miles/well)	11,000	16,800
Saline (0.7 miles/well)	—	2,900
Private—Special (0.4 miles/well)	2,400	3,500
Routine (0.2 miles/well)	1,800	2,600
Total Miles of Line	24,700	42,600
Adjusted	20,700	35,600

[a] 'Special' private tubewell projects were envisaged as the extension of the distribution system to a whole new area where private wells would be installed.
[b] 'Routine' private tubewell connections were those that would take off from existing lines.
[c] 40 customers/mile in the Fourth Plan period (1970–75).

that, if electrification of private wells is justified economically at all, it will be justified up to a certain distance from an existing transmission line or, what comes to the same thing, at a certain density of private wells, but not at greater distances or lower density. Even then the answer remains unclear, given the uncertainty that inevitably exists regarding additional tubewells or other loads that may develop subsequently in the vicinity of the distribution line as a result of the stimulus afforded by its existence.

The Study Group has attempted some computations relating to the comparison between diesel and electric private tubewells on the basis of the best evidence available to it early in 1967 regarding average economic prices (i.e. prices excluding duties and taxes). The procedure adopted below is to calculate the present-worth costs of a one-cusec diesel well, with a 10-year life, pumping about 200 acre-feet a year and to compare them with the present worth capital and maintenance costs of an electric well with the same life and pumping the same quantity of water each year. The difference between these costs, when set over the present worth of the total quantity of electricity required to drive the electric well over its 10-year life, indicates the price per kwh at which the economic costs of diesel and electric wells break even. This in turn can be compared with the economic cost of electricity. Depending on the specific assumption initially made regarding the length of distribution line required to connect the private well, an indication can thus be obtained as to the maximum distance from existing distribution lines at which it is worthwhile electrifying private tubewells.

All the surveys that have been made of the capital costs of private tubewells indicate that they vary over a very wide range.[1] Nevertheless the figures in Table 5-3 seem to indicate reasonably well the order of magnitude of the capital costs of one cusec diesel and electric wells. The difference in capital costs occurs entirely in the cost of the motor/engine—diesel costing about twice as much as electric. Both electric motors and diesel engines are manufactured in Pakistan, but imported materials and components are very important in both. It is estimated that the real foreign exchange component is about 50 percent of the cost of each.

[1] IACA's Comprehensive Report, Volume 5, Annexure 7—Water Supply and Distribution, p. 36.

TABLE 5–3
CAPITAL COSTS OF DIESEL AND ELECTRIC ONE-CUSEC TUBEWELLS
(Rs.)

	Electric		Diesel	
	Total	Foreign Exch. Component	Total	Foreign Exch. Component
Drilling	500		500	
Lining	800		800	
Screens	1,000	300	1,000	300
Pit and Shed	1,200		1,200	
Pump	500	1,500	500	2,750
Motor/Engine	2,500		5,000	
	6,500	1,800	9,000	3,050

In terms of direct capital cost, an electric well thus appears to be significantly cheaper than a diesel well, but, when account is taken of the costs of installing the requisite distribution lines, it is clear that the electric well involves a much greater initial capital outlay. 'Theoretical' costs of constructing distribution lines and connecting private wells, on the assumption that a complete network of wells can be established in a diagonal array so that quantities of lines per well are minimized, are of the same order of magnitude per well as the total direct capital costs of an electric well cited in Table 5-3. Practical experience has shown that the cost incurred by WAPDA in connecting private wells has ranged between somewhat less than Rs. 10,000 and nearly Rs. 50,000 per well. The duty on distribution equipment is relatively high in West Pakistan, so that economic costs would have been substantially less—perhaps a maximum of something under Rs. 40,000.

It appears that typical experience has been to build about half a mile of distribution line—partly 11-kv and partly 400-volt line—per private tubewell. A reasonable figure for the costs of these lines (including lattice steel structures, insulators, guys, anchors, conductors, etc. and erection) would be about Rs. 20,000 per mile. Some lower and some higher figures have been cited, but this appears to be a conservative estimate, erring towards the high side. Besides the lines, a step-down transformer is required of about 10 kva—or larger if there are other loads in the neighborhood. And there is the actual service connection (installation of meter, etc.). Table 5-4 summarizes these costs. About 25 percent of this total is estimated to be tax and duty, and about 30 percent foreign exchange. Thus the economic cost per well is about Rs. 8,500 with a foreign exchange component of Rs. 3,400. Addition of these to the direct cost items (Table 5-3) suggests a total economic cost per electric tubewell, including connection with the distribution system, of about Rs. 15,000, with a foreign exchange component of about Rs. 5,200.

Maintenance costs tend to be considerably higher on diesel wells than on electric wells. They are estimated at about Rs. 500 per annum on electric wells, including spares, as compared with about Rs. 1,000 per annum on diesel wells. No allowance has been made for any foreign exchange component in maintenance costs.

Diesel oil, as pointed out above, bears a very heavy tax, but even without the tax it is expensive compared with electricity and it has a high foreign exchange component. By agreement between the Government authorities and the marketing companies diesel oil is sold at a uniform ex-depot price throughout West Pakistan. This price represents an agreed fixed sale price ex-depot Karachi, including taxes,

TABLE 5-4
COSTS OF CONNECTING A PRIVATE TUBEWELL TO THE DISTRIBUTION SYSTEM
(Rs.)

	Costs (including taxes and duties)
½ mile of 400 volt/11 kv line	10,000
Transformer	1,100
Service connection	200
Total	11,300

plus a surcharge to cover freight Karachi-Rawalpindi. The surcharge for freight goes in the first place to the Government but is recoverable by the marketing companies to the extent it is needed to cover freight costs incurred by them. Some of the private tubewells in existence in West Pakistan have light engines, doing about 1,500 rpm, and using High Speed Diesel Oil (HSD), but more typical is a low-speed 160-rpm engine using Low Speed or light diesel oil. Table 5-5 summarizes the components of the current costs of a gallon of each type. The freight surcharge is treated as a cost rather than a tax. The table indicates that the net-of-tax prices for the two types of diesel oil is very close, at about Rs. 0.90 and Rs. 1.00 per imperial gallon. Since most tubewell-using farmers are not as far from Karachi as Rawalpindi is, the rail portion of the transit to them would cost less than Rs. 0.27 per gallon; thus it would seem that a reasonable economic price for diesel fuel used for agricultural purposes would be about 85-95 paisa per imperial gallon. Since a one-cusec 16-hp diesel well would require about 1,750 gallons to pump 200 acre-feet, the annual fuel cost, at a diesel oil price of about 90 paisa per gallon and with a small allowance for lubricating oil, would be about Rs. 1,614, with a foreign exchange component of about Rs. 700.

Cost streams are given in Table 5-6. They represent capital and maintenance costs on an electric well and capital, maintenance and fuel costs on a diesel well, discounted back to 1967 at eight percent, resulting in the present-worth figures indicated at the bottom of the Table. The shadow exchange rate adopted was twice the current exchange rate. The amount of electricity required to raise about 200 acre-feet from a well with a pumping head of about 35 feet, assuming a 40 percent wire-

TABLE 5-5
CURRENT PRICE OF DIESEL OIL IN WEST PAKISTAN
(Rs. per Imperial Gallon)

	Light (Low Speed)	HSD (High Speed)
Import/Excise Duty	0.46	1.08[a]
Defense Surcharge	0.12	0.27
Development Surcharge	0.07	0.11
Total Tax Component	0.65	1.46
Development Surcharge (Freight)	0.25	0.27
Karachi Selling Price	0.50	0.56
Total ex-depot price	1.40	2.29
Agents' commission	0.02	0.03
Average Octroi at depot station	0.02	0.03
Average delivery charge	0.05	0.05
Agents' handling cost	0.07	0.07
Price delivered farmer (incl. taxes)	1.56	2.47
Price delivered farmer (excl. taxes)	0.91	1.01
Direct foreign exchange cost	0.38	0.40

[a] Since June 1963 farmers have been entitled to a rebate of 20 percent of the duty on HSD sold to them for use in tractors, tubewells and lift pumps for agricultural purposes: allowance for this rebate would make the price delivered to the farmer including taxes about Rs. 2.26 per gallon.

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well at the time of system peak,[1] the costs of generating capacity required to cover the tubewell load. As the WAPDA system expands and includes more hydro-generation at dams for which the primary justification is agricultural—meaning that relatively small proportions of the capital costs are attributable to power—WAPDA's unit costs will decline. But the best figures available for the present comparison seem to be historic ones. WAPDA's total operating costs in fiscal 1963/64, including fuel, maintenance of all equipment and establishment charges, but excluding depreciation and interest charges, averaged 4.5 paisa per kwh. As regards capital costs of generation, a reasonable allowance would be annual depreciation (assuming a 20-year life) and interest charges (at eight percent) on the capital cost of gas turbines (assumed in this Report at $107 or Rs. 509 per net kw installed, excluding taxes, duties and interest during construction, with a foreign exchange component of about 85 percent). The annual capital charges for 8 kw of generating capacity would be about Rs. 367 or, divided by 20,000 kwh, 1.8 paisa per kwh; at the higher foreign exchange rate they would be about 3.4 paisa per kwh. However this would not be an adequate allowance for capital costs of generation, since it fails to allow for transmission and distribution losses—which will inevitably be high on sales to private tubewells. These losses may range anywhere from about 40 percent to as much as 100 percent of sales. A reasonable assumption would be 75 percent losses, so that the allowance for generating capacity must be 175 percent of the charges for the 8 kw peak load of a private tubewell cited above.

The results of these computations are summarized in Table 5-7, which suggests that the overall economic costs of driving a one-cusec well electrically, assuming it involves construction of not more than half-a-mile of distribution line, compare favorably with the costs of driving such a well with a diesel engine. If the private tubewell can be interrupted at the peak (it might then have to have some 10 per-

[1] The Study Group's consultants have assumed that it is impractical at present to interrupt private tubewells. Private tubewell load has, of course, been shed in the past—particularly during the power crisis of 1966/67—but only by means of switching off power supplies to a whole area or by voluntary cooperation of the farmer, since there is no centralized control system for agricultural wells alone. The power consultant suggests that, after experience has been gained with interruption of public wells, it may become feasible and worthwhile to extend the control system to private wells.

TABLE 5-7
COST OF ELECTRICITY: DELIVERY PRICE VERSUS BREAK-EVEN PRICE
(paisa per kwh)

	Current Exchange Rate	Shadow Exchange Rate
Unit Cost of Electricity		
Current Costs	4.5	4.5
Capital Charges (generation)	3.2	6.0
Total	7.7	10.5
Break-Even Price of Electricity (Diesel vs. Electric Wells)		
Without Allowance for Full Life of Distribution System	6.1	8.0
With Allowance for Full Life of Distribution System	8.0	10.5

cent larger installed capacity, but the costs of this extra capacity would be small) the comparison would be much more favorable to electrically driven wells because the capital charge component on the electricity would be eliminated. The break-even price is in effect the maximum price that the farmer could afford to pay for electricity (assuming he were charged economic prices), under the given conditions, because if the price were higher it would be preferable for him to use a diesel engine. The table shows that, at the current exchange rate, the price he could afford to pay is slightly higher than the unit cost of electricity, while at the higher foreign exchange rate the prices are identical.

Given the fact that the real economic cost of electricity is likely to show a downward trend, whereas there is no reason why the economic cost of diesel fuel should fall,[1] the weight of economic argument seems to favor installation of electric motors rather than diesel engines on private tubewells whenever the need for distribution line is less than about half-a-mile per well. As costs fall, and more particularly if interruption of private wells becomes possible on a planned basis, then this 'maximum length of line justifiable' will increase substantially towards about one mile per well.

Distribution-Line Requirements of Recommended Program

It was suggested above that the average length of line which WAPDA has had to install in recent years to connect private tubewells may be about half a mile. Table 5-2 showed that S&W had assumed that about 0.4 miles of line would be required per well to connect private wells in 'special private tubewell electrification project areas' and about 0.2 miles would be required per well for routine connections taking off from existing distribution and transmission lines. These allowances seem on the low side compared with Harza's calculations that indicated about 0.3-0.4 mile per well, on the assumption that the wells could be laid out in perfect grid pattern. In practice, private tubewells will be very irregularly spaced.

The number of tubewells finally projected under the Study Group's program is also different from the number assumed by S&W in their report (Table 5-8). The Study Group has not made separate projections of the number of private tubewells which will be electrified, and the load forecasts used in the studies described in these volumes have been based on the IACA projection of electrified private wells. The Study Group's projection of the total number of private wells which will be in existence over the next decade is somewhat larger than IACA's: 55,500 by 1970 against IACA's 52,000 and 52,500 by 1975 against IACA's 48,000. But the differences between the Study Group's final projection and IACA's are not large.

The difference between the numbers of electrified private wells projected to exist at the beginning and at the end of a five-year period is not a good indication of the

[1] It might in fact rise if there was a very sharp increase in the amount of diesel fuel required in West Pakistan, unaccompanied by any comparable increase in the demand for fuel oil. Either the diesel oil would have to be imported as such (whereas the prices used here are those applicable to the products of the Karachi refineries) or the refineries would produce larger surpluses of fuel oil than they do now; these current surpluses are already a problem and are sold abroad at relatively low prices.

TABLE 5-8
PROJECTIONS OF PUBLIC AND PRIVATE WELLS
(numbers)

	1965	1970	1975	1985
Stone & Webster's Report				
Public	2,015	10,565	27,650	33,150
Private[a]	12,250	27,150	49,050	88,350
IACA's Program				
Public	2,200	9,500	20,000	44,100
Private[a]	9,000	17,000	24,000	23,000
Study Group's Program				
Public	2,200	9,600	20,700	

[a] Electrified wells only, including those both inside and outside the canal commanded areas.

number of electric well installations projected for that period because it is assumed that existing private wells, including electric ones, will be largely eliminated as the area in which they are located comes under the public tubewell program. Taking account of the regional distribution of private electric wells and of the areas to be covered by the public well program, we can estimate that the number of private wells expected to be electrified over the coming years under the Study Group/IACA program is about 8,500 during the Third Plan and 14,000 during the Fourth Plan.

On the basis of data provided by WAPDA regarding miles of distribution line constructed during the Second Plan period for the public tubewell program and for other purposes, and using Stone & Webster's assumption that about 50 nonagricultural customers are connected per mile of 11-kv and 400-volt line installed, it is possible to make a rough estimate of the amounts of distribution line that will be required to implement the program recommended in this Report, and bring loads up to the levels forecast here. Approximately 363,000 new nonagricultural customers were added to the WAPDA system during the Second Plan. If one mile of distribution line was required for every 50 such customers, making a total of about 7,200 miles of line, then the remainder of the total built during the Second Plan—about 7,500 miles of line—must have been for agricultural customers; about 1,800 miles were for public tubewells, according to WAPDA's data, so the rest must have been for private tubewells. This assumption leads to an average figure of 0.5 miles of line per private tubewell connected during the Second Plan. This figure is used as the basis for projecting the miles of line required for private tubewell electrification in the following table.

According to the rough projections given in Table 5-9, WAPDA will need to construct about 23,000 miles of distribution of line during the Third Plan and 35,000 miles during the Fourth Plan. This would mean improving on the performance of the Second Plan by about 60 percent during the Third Plan and more than doubling Second Plan performance during the Fourth Plan. These do not seem impossible targets, although they are ambitious. They appear to be attainable within the rupee estimates given in Volume I for capital expenditures on distribution during the Third and Fourth Plan periods.

TABLE 5-9
WAPDA SYSTEMS: NEW CUSTOMERS CONNECTED AND MILES OF DISTRIBUTION LINE REQUIRED, 1960-75

	Second Plan	Third Plan	Fourth Plan
	(1960-65)	(1965-70)	(1970-75)
Numbers of New Customers			
Nonagricultural	363,000	500,000	700,000
Public tubewells	2,100	7,000	11,000
Private tubewells	11,400	8,500	14,000
Total	376,500	515,500	725,000
Miles of Distribution Line Required			
for Nonagricultural[a]	7,260	10,000	14,000
Public tubewells[b]	1,806	9,100	14,300
Private tubewells[c]	5,637	4,250	7,000
Total	14,703	23,350	35,300

[a] Assume 50 nonagricultural customers per mile of line.

[b] Figure for Second Plan is actual, as reported by WAPDA; figures for Third and Fourth Plans are projected at 1.3 miles of line, following SCARP reports.

[c] Figure for Second Plan is residual from total miles of line built after subtracting allowances for nonagricultural customers and public tubewells (see footnotes a and b). Adopting the WAPDA agricultural customer figures as the best indication of new electric well installations during the Second Plan, we find this works out at about 0.5 miles per private tubewell. This per-well figure is assumed to continue to apply through the Third and Fourth Plan periods.

PART THREE

The Power Simulation Studies

Introduction

The ability of the Bank Study Group to study the problems of system development in a program context was largely due to the availability of a computer model that simulated the operation and growth of the electric power system of West Pakistan, month by month, over the period 1966–85. This simulation model was set up essentially as a tool for comparing alternative programs for the development of generation and bulk transmission in all the main power markets of West Pakistan. Data were fed into the computer regarding the capabilities, heat rates, fuel cost and operating costs of possible new thermal plants; the capital and operating costs and monthly patterns of capability and energy output, with different numbers of units installed, of the existing and proposed hydroelectric plants; the capital and operating costs and carrying capacities of proposed transmission lines between Lyallpur and Mari and between Mari and Karachi; economic factors such as discount rates and foreign exchange rates; and, finally, details of the prospective monthly loads over the 20-year period 1966–85, in each of the three main markets in the country. The computer was then given a "strategy," or schedule, according to which the various thermal plants, hydro plants and transmission lines will be added to the system (or, in the case of plant retirements, removed from the system) over the 20-year period. The computer calculated and added up all the costs involved in the operation of the system (capital costs, maintenance and operating costs and fuel costs) in each year of the Plan period, computing them under different assumptions regarding fuel prices and the foreign exchange rate, and discounted them back to 1965. The end result was an array of figures representing the present worth of total system costs over the 20-year period, at different fuel prices and foreign exchange rates.

The Study Group's experience in the preparation of this report has convinced it that such a computer model, simulating the operation of the West Pakistan power system, could be of considerable assistance to the Pakistan authorities in reaching decisions regarding investments in power generation and transmission. Many of the difficulties encountered by the Group are inherent to the planning process. For example, soon after the consultants finished their work, important changes took place in the best estimate of fuel reserves in West Pakistan. As a result, as will become apparent in the following papers, important conclusions regarding transmission and the location of thermal capacity had to be reanalyzed. WAPDA is continuously up against this difficulty; almost every report which it receives (and this will, of course, apply equally to this one) is, by the time that it finally appears, to a greater or lesser degree out of date. The conclusions and recommendations regarding system development which are presented in this volume are based on the best data available to the Study Group in early 1967. Inevitably, there will soon be further changes in basic data—perhaps, for instance, about the thermal value of Lakhra coal or the price of gas turbines—which will make it necessary to reanalyze some of the conclusions reached here. Planning has to be a continuous process; but it also has to be a quick process if decisions are based on the best information available at the time they are made. It is essential therefore that an approach be used which will enable the identification of the implications for system development of changes in knowledge of fuel resources, expectations regarding loads, etc., as and when they occur. It is because of its belief in the usefulness of a simulation model for this purpose that the Study Group has included in Supplemental Paper No. 9 a considerable amount of detail about the particular model which it used and about the way it works. The model itself could undoubtedly be improved and made more comprehensive, but the Group feels that the type of approach made possible by use of a system simulation model could help considerably both to accelerate and to improve Government decisions regarding power system development.

Parallel and closely interlinked to the formulation of the irrigation development program are the methods used to prepare a comprehensive plan for development of the power sector. The assumption adopted for the second phase of the Study—that Tarbela Reservoir would be completed by 1975—was as important for the formulation of the power program as it was for the irrigation program. The hydroelectric potential of Tarbela is so large relative to prospective power loads that a sensible action program for interim power development would need to anticipate the existence of Tarbela in 1975. The power characteristics of the Tarbela and the Mangla plants had to be determined for different assumptions as to flows, reservoir release patterns, number of generating units installed, etc., as discussed in Supplemental Paper No. 6. Special reservoir simulation studies were undertaken to indicate the implication for power of different modes of operation. Because the data on the irrigation program were subject to so much study and review, the power consultant had to make certain interim assumptions about tubewell pumping loads and reservoir operation and proceed on that basis to formulate a power program. Rather than use a fully integrated system analysis, the power consultant relied on judicious partial analyses related to his judgment of the overall character of the power system and the relative attractiveness of individual investments. Various alternatives were compared by hand.

In its review of the proposed power program, the Study Group's objectives were similar to those adopted in its review of agricultural and water proposals: to build up procedures which would enable it to broaden the range of alternatives and to test the economic efficiency of the consultants' proposals. In addition it was hoped to contribute to the process of developing techniques appropriate for updating over time the power program finally recommended. Using the simulation model of the electric power system of West Pakistan discussed in Supplemental Paper No. 9, the Study Group compared the costs and operational characteristics of alternative proposals. This analysis played a central role in the formulation of the Group's conclusions and recommendations; the power consultants' bulk supply proposals were checked with the aid of the simulation model, and some alterations were made on the basis of analyses.

The power program (outlined in Volume One), and particularly the role played by Tarbela in it, is of an entirely different order of magnitude from any generating plant constructed in West Pakistan in the past. Tarbela's installed capacity of 2,100 mw is more than twice the capacity of all existing generating equipment in the

Province and more than five times the 1965 peak load on the largest of the existing power systems. There are other important features peculiar to a program including Tarbela that need special consideration. Under the current construction schedule, it will take eight to nine years to build Tarbela. Current schedules foresee the installation of 12 175-mw generating sets by the early 1980's. Because the primary purpose of the dam is to create a reservoir for over-seasonal storage—storing water in the flood season for subsequent release for irrigation purposes in the dry season—the heads on the turbines and hence the peak loads that they can carry will fluctuate tremendously over the course of a year; peak capability in the flood season of about 2,500 mw (with 12 units installed) may be four to five times as great as the capability available in the spring when the reservoir has been drawn down to meet irrigation requirements.

One of the prime tasks of this Report was, therefore, to reassess the power benefits of Tarbela within this context. The procedure is described in Supplemental Paper No. 7. A precise definition of the power benefits attaching to such a project was a difficult question. Electric power is sold at an administered price that may not give a good indication of the true average market value of electric power, let alone its marginal value. At the same time, electric power is generally a very small item in the total budget of an individual enterprise or household; also, supplies of power from an electric utility can usually be substituted by generation by an enterprise itself or by other forms of energy. In this sense, electric power is different from irrigation water, which is critical to the agricultural production process and a less easily substitutable input than electricity supplied by a utility. However, the availability of several ways to produce electricity means that it is possible to define alternative power development programs for meeting a projected power load. One program, for instance, can be built up including Tarbela and another excluding it, and both have to be refined to ensure that they are reasonable approximations to what would be the best course of action, as far as can now be foreseen, under the two assumptions. Then the economic costs of the two programs (i.e., costs excluding duties, taxes and interest during construction) can be discounted to a common basis—generally 1965—and compared to indicate which of the two puts a smaller burden on the economic resources of West Pakistan. Costs discounted to 1965 are generally referred to in this volume as "present-worth costs." Net benefits of a particular project, e.g., Tarbela, are defined as the difference between the present-worth cost of the best program including Tarbela and the present-worth cost of the cheapest alternative program excluding Tarbela which can meet the same requirements of power with equivalent reliability of supply.

Most of the discussion above is in terms of alternative power programs rather than alternative power projects; and, in fact, it was largely by means of comparison of programs that the Group carried out its studies. An electric power system is such a tightly integrated entity that it is hard to see what will be the impact of any particular system addition except in the context of an overall program. This is because fuel costs represent a relatively large proportion of the total expenses of an electric utility, and they are determined by the complex interaction of different system elements. For example, fuel accounts for about 30 percent of the total expenses, including interest and depreciation, of the Karachi Electric Supply Corporation, Ltd. (KSC) and for between 15 and 20 percent of the total expenses of WAPDA (considerably less for WAPDA mainly because hydroelectric supplies are more dominant in WAPDA's system). Addition of a new thermal plant to a system may have the effect of reducing total system fuel costs if it is much more efficient than existing plants and consequently takes over supply of most of the energy previously produced by them. The effect of a new hydroelectric plant on total system fuel costs will be much more complicated, especially if, like Tarbela, it has a power output which varies significantly at different times of the year. Depending on the size of the power demand and on the variation of demand over the course of the days and weeks, it may, for instance, be impossible to absorb all the energy that the hydroelectric plant can produce even though thermal equipment has to be brought into use at the same time. This may sometimes be the case with Tarbela in the Spring when the heads on the turbines are low so that the instantaneous load which they can carry is severely limited. In some other months, such as during the release period, it may be energy rather than peaking capacity which will be limited at Tarbela; in other months, Tarbela may simply produce more energy and have more capability than the system can absorb. The effect of these varying patterns of power output at Tarbela on system fuel costs will vary considerably, depending on what other hydroelectric plants are on the system at the same time and the nature of their power outputs at different times, and depending on whether transmission capacity is available to carry power to the South, and also on the extent and location of thermal capability on the system.

SUPPLEMENTAL PAPER VI

Hydroelectric Projects and Problems of Reservoir Operation

The central purpose of the studies discussed in this Paper was to analyze the development of West Pakistan's hydroelectric resources over the next 20 years and to consider how recommended hydroelectric projects might best be assimilated into the power system. The Province's total hydroelectric potential has been conservatively estimated at about 10 million kw, of which less than 250,000 kw had been developed when this study was undertaken. This Paper reviews briefly the main rivers of West Pakistan, focusing on characteristics that are important from the power point of view. Hydroelectric projects that have been studied in some detail are related to the general hydroelectric potential of the Province. And the main questions regarding hydroelectric development that are considered in the following several Papers are introduced as well as the procedures adopted for estimating the power potential of alternative hydroelectric developments and alternative patterns of reservoir operation.

THE MAJOR RIVERS OF WEST PAKISTAN

The Indus main stem and its principal tributaries, the Kabul, Jhelum, Chenab, Ravi, Beas and Sutlej form a link between two great natural reservoirs, the snow and glaciers in the mountains and the groundwater contained by the alluvium in the Indus plains in West Pakistan and India. The total rim-station discharge into the plains averages about 175 MAF a year, a little more than one-third of it in the Indus itself. When the Indus Waters Treaty of 1960 is fully implemented, the flows of four main rivers will be available to Pakistan—the Indus, Kabul, Jhelum and Chenab, which have a combined average annual discharge of about 142 MAF. Nearly one-half of this discharge is in the Indus itself and the remainder roughly equally divided between the other three rivers.

The Indus River rises in Tibet, in a catchment which contains some of the largest glaciers in the world outside the Polar regions. Snow and ice melt from this glacial area of about 14,000 square miles probably supply about half the total flow of the Indus in the summer season. The importance of this source helps to account for two significant characteristics of the flows in the Indus—their relatively high seasonal concentration and their relatively small fluctuation from year to year. Of the total mean flow of the Indus at Attock (below the confluence of the Kabul), about 72 percent (or 67 MAF) occurs in the four months June to September. Annual mean flow on the Indus at Attock is about 93 MAF and the range of recorded flows is about 75-118 percent of this. The difference between mean annual yield and the yield which would be exceeded in three years out of four is only about six percent. The Indus River falls rapidly between the place where it crosses the cease-fire line from Indian-held Kashmir and Chasma, where it debouches into the plains—nearly 8,000 feet in 600 miles. Three-quarters of this drop is concentrated in the so-called Indus Gorge, about 300 miles long, between Skardu and a point some 30 miles downstream of Tarbela Dam site. In the 900 miles over which the river flows between Chasma and the Arabian Sea, on the other hand, the river drops only about 500 feet in total.

The Jhelum is a very different type of river from the Indus: mean annual flows are only about one-third of those in the Indus and they are much more variable from year to year. The river rises in Indian-held Kashmir at a much lower elevation than the source of the Indus and it falls much less rapidly than the Indus after entering Pakistani territory. Snowmelt accounts for some of the flows in the Jhelum, but it is much more dependent than the Indus on variable monsoon runoff. Partly as a result, flows in the Jhelum are less concentrated within a few months—only about 12 MAF or 53 percent of the total mean flow occurring in the four peak months—but they are more variable from year to year. Annual recorded flows at Mangla range between 65 percent and 135 percent of the mean flow of 23 MAF. The difference between mean annual yield and the yield which would be exceeded in three years out of four is over 12 percent or more than double the comparable difference on the Indus. The Jhelum falls about 1,000 feet in 100 miles before it is joined by the Kunhar River. Between the confluence of the Kunhar and Mangla it drops a further 1000 feet in somewhat more than 100 miles to an elevation of about 1000 feet above mean sea level at Mangla.

The Chenab and the Kabul are rivers of less importance from the point of view of hydroelectric development in West Pakistan over the next 20 years—the Chenab, because of its lack of suitable sites, and the Kabul, because it is already partly developed and because development on the basis of Kabul water in the near future would probably be on the Indus main stem downstream of the confluence.[1] The Chenab, with mean flows of about 26 MAF, is a river of somewhat similar flow characteristics to the Jhelum; low years on the Chenab are often also low years on the Jhelum. It falls less than 500 feet in about 400 miles between the Marala Headworks near the Indian border and the confluence with the Panjnad. Chenab flows in the summer are somewhat more reliable than those on the Jhelum. The Chenab river is a very important source of irrigation supplies and, since it commands many of the same areas as the Jhelum, regulation of the Jhelum has to be planned taking into account Chenab flows. The Kabul River, which rises in Afghanistan and is being partly developed there for hydroelectric and irrigation purposes, has more variable flows than any of the other three rivers. Mean flows on the Kabul above Warsak are estimated at about 17 MAF per annum; Surface Water Circle records indicate that, over the period of record since 1921/22, flows have ranged between about 65 percent and more than 160 percent of mean. Mean

[1] However, the so called Pak-Afghan site upstream of Warsak at the border between Pakistan and Afghanistan could turn out to be very valuable for storage and for power. WAPDA believes that a large reservoir could be built in the area; siltation would be significantly less relative to the size of the reservoir than at most of the other sites discussed in this Report. However, no specific dam site has been identified and there is virtually no information available on the potential project.

flows on the Kabul at the point where it joins the Indus are estimated at about 27 MAF. In the relatively short distance of about 100 miles, between the border with Afghanistan and the confluence with the Indus, the Kabul drops some 400 feet.

Besides the distinctions between the Indus and the Jhelum drawn above, there are a number of other differences between the two rivers which are significant from the power point of view. There is an important difference in the time when flows start to rise to a summer flood peak and in the length of time that flood flows endure. The hydrographs of both rivers show a rising stage in the early spring entirely due to snowmelt, the Jhelum being the first to respond at the end of January and continuing to rise to its highest level in May, June and July. The Indus, together with the Kabul, on the other hand, starts to rise later at the end of February reaches its highest snowmelt peak flows at the end of June; the Indus continues to rise to a higher monsoon peak early in August. The Jhelum enters a falling stage at the beginning of August and the Indus toward the end of the month; this generally continues, with the exception of rare monsoon rain floods in September, to the end of the year. The winter base-flow discharge on both rivers is largely maintained by bank storage water contained in the valley alluvium and this regeneration makes an important contribution to the available water supplies in rabi.

A further difference between the flows on the two rivers is the very much higher silt content of the Indus. Almost all of the sediment inflow occurs in conjunction with the flood flows of the early summer. The generally accepted figure for mean-year sediment load on the Indus at Tarbela is 440 million tons—equivalent to about 0.25 MAF compacted volume. Mean-year sediment transport on the Jhelum at Mangla, on the other hand, is estimated at 72 million tons or about 0.04 MAF compacted volume. Whereas Mangla reservoir is expected to lose by siltation about 30 percent of its capacity in 50 years, the much larger Tarbela reservoir will lose an estimated 90 percent in the same period.

Existing Hydroelectric Installations

Of the 250,000 kw of hydroelectric potential that has so far been developed in West Pakistan, about 60 percent is in the seven-year-old Warsak plant on the Kabul River and the remainder is distributed in a number of small installations located on irrigation canals or minor rivers in the Northern Grid area. The combined peak capability of the units is about 245 mw in summer and 155 mw in December. The characteristics of these various installations are summarized in Table 6-1.

The Warsak station near Peshawar, which was commissioned in 1960, contains four 40-mw units. Each unit is capable of generating 40 mw at normal operating head, using a discharge of 4,000 cusecs. Natural river flow is insufficient to sustain all four units at 100 percent capacity factor from the latter part of September to the early part of April. The reservoir initially had pondage of only about 23,500 acre-feet and this has been reduced by siltation to an estimated 15,000 acre-feet or less. The minimum residual capacity of the reservoir has been estimated at 10,000 acre-feet. This should mean that some peaking capability will always be available. However, the peaking capability of the plant is in practice restricted at present to about 100 mw in winter from October through March; this restriction flows on the Kabul at the point where it joins the Indus are estimated at about 27 MAF. In the relatively short distance of about 100 miles, between the border with Afghanistan and the confluence with the Indus, the Kabul drops some 400 feet.

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Whether it will ever become technically and economically feasible to build such a series of dams are questions that will probably not be answered until future centuries. Besides the Indus Gorge itself there are a very large number of other potential hydroelectric dam sites in West Pakistan, especially on some of the tributaries of the major rivers discussed in this Paper; these sites are listed and discussed in the report by the dam sites consultant;[2] the vast majority of them are no more than locations that appear to have the basic topographical features that are, with present technology, required to make the construction of a dam even prima facie feasible.

There are, however, a number of dam sites in West Pakistan that have been surveyed with sufficient thoroughness to make them potential contenders for construction before the end of the century; Table 6-2 lists the principal among these. For comparative purposes, the table includes Mangla Dam on the Jhelum, which is considerably more than a 'contender' since it is now completed. An important possibility over the next twenty to thirty years is to raise Mangla 48 feet; this would permit its live storage capacity to be increased by about 3.6 MAF. The main possibilities on the Indus are the Tarbela project, which was of course still a contender during these studies and the much less fully known Kalabagh dam site, some 120 miles downstream of Tarbela. A possible project following Tarbela would be side valley storage at Gariala on the Haro River, a minor tributary of the Indus. Finally, there is the Kunhar project, consisting of two dams in series on the Kunhar River (a tributary of the Jhelum) some 125 miles north of Mangla in the Kaghan Valley. The maximum total installed capacity of the different projects listed in Table 6-2 is about five million kilowatts.

Surface Storage for Irrigation Purposes

A large part of the need for the construction of dams on the Indus and its tributaries arises from the agricultural requirements for additional supplies of irrigation water, as indicated by the relatively large amounts of live storage envisaged in Table 6-2 behind most of the dams listed. The main purpose of the Mangla Dam is in fact to replace the rabi irrigation supplies which have been available to Pakistan from the Ravi and the Sutlej but which are allocated to India under the 1960 Indus Waters Treaty. The main purpose of subsequent surface storage development within this century will be to reconcile the seasonal fluctuations of river flow with the conflicting seasonal variations in requirements of irrigation water. The present periods of shortage of irrigation water are generally between mid-October and mid-April. The irrigation consultant anticipates that, with the growth of cropping intensities, this period of shortage will gradually expand to include more of October, April, and the early part of May. A later stage of surface storage development, which might perhaps come into effect around the year 2000, would be to build reservoirs for over-year storage, i.e. to store flows from years with high floods for use in years when surface water supplies were below average.

The irrigation and power benefits of such dams are inseparably intertwined. Therefore the approach adopted by the Study Group and its consultants in the evaluation of the various projects listed in Table 6-2 was to prepare various estimates of future requirements of electric power and of stored water for irrigation

[2] Chas. T. Main International, "Program for Development of Surface Storage in the Indus Basin and Elsewhere within West Pakistan," in six volumes (August, 1966).

TABLE 6–2

POWER POTENTIAL OF SOME PRINCIPAL POSSIBLE DAMS

	Full Supply Level (ft.)	Minimum Reservoir Level (ft.)	Initial Live Storage[b] (MAF)	Approximate Net Head (ft.)[a]		Ultimate Number of Power Units Envisaged	Power Units nominal rating (mw)	Approximate Capability One Unit (mw)	
				Full Reservoir	Minimum Reservoir			Full Reservoir Level	Minimum Reservoir Level
Jhelum River									
Mangla	1,202	1,075	4.9[c]	352	227	8	100	130	65
	1,202	1,040	5.3[c]	352	192	8	100	130	47
High Mangla	1,250	1,040	8.9[c]	403	227	8–10	100–125	134–165	47
	1,250	1,175	4.9[c]	403	335	8–10	100–125	134–165	124
Indus River									
Tarbela	1,550	1,300	9.3	435	185	12	175	200	38
	1,550	1,332	8.6	435	217	12	175	200	61
Kalabagh	925	825	6.4	220	120	9+	110	117	41
Haro River									
High Gariala	1,250	1,070	7.6[d]	340	160	6	85	90	33
Kunhar River									
Suki-Kinyari/Paras			0.128	3,000(±)	3,000(±)	4	110	122	110
Naran/Suki Kinyari			0.250	1,100(±)	1,100(±)	3	40	50	40

[a] Not a single value, but one which will vary with both unit and total discharge and with erosion of original control section.

[b] Does not include streamflow available for power generation.

[c] These include 0.4 MAF in Jari arm below Mirpur saddle which can be used for irrigation purposes but not for power generation until a cut is made through the saddle. From the power point of view Mangla has live storage of 4.5 MAF (minimum drawdown level 1,075 feet) or 4.9 MAF (minimum drawdown level 1,040 feet).

[d] Streamflow negligible.

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[d] Streamflow negligible.

a very different type of project from Tarbela; it is much smaller, but it would develop a much higher head than Tarbela and, any agricultural use that might be made of its storage being definitely a secondary consideration, its capacity and its energy output fluctuate much less over the year than would those at Tarbela. Table 6-3 sets out some of the chief characteristics of these two projects. The Table illustrates the very large variation in the peak capability of the Tarbela units resulting from the fact that, due to release of water for irrigation purposes, the net head available would fluctuate between about 435 feet in August-November and 217 feet in early June. The fact that the annual capacity factors of Kunhar and Tarbela with 12 units are identical is a coincidence. In fact, the capacity factor at Kunhar would be relatively constant over the months at about 55-60 percent; that at Tarbela would change from about 100 percent, in May and June (when relatively small flows are required to keep the turbines running continuously at maximum output because of the low head) and in the flood season August-September, to as low as 40 percent in November-December when the head would still be quite high (relatively small storage-releases having been made up to that time) but flows relatively low.

After consideration of these two projects in the context of power development programs modeled around them, attention was turned to the more specific question of the timing of Tarbela. For analysis of this question alternative complementary programs of power development and surface storage development were devised in a manner similar to that used in assessment of Kalabagh, but in this case one program included the Tarbela project in 1975 and the other had Tarbela in 1985. Both sets of programs were intended to meet the power requirements and the stored water requirements derived in other parts of the study and built up into an internally consistent overall development plan. The programs are described more fully in Paper No. 8. One of the major ways of compensating for the lack of Tarbela storage in the decade 1975–85 is by means of raising Mangla in 1975 and continuing to draw the reservoir down to 1040 feet each year. The higher reservoir level at the end of the flood season and larger releases through the winter that would result from operating Raised Mangla in this way would make its power

TABLE 6–3
COMPARISON OF KUNHAR AND TARBELA POWER POTENTIAL

	Tarbela (Drawdown: 1,332 feet)	Kunhar Project
No. and Size of Units	12 × 175 mw	4 × 110 mw 3 × 40 mw
Maximum Capability (mw)	2,520 (Aug.-Nov.)	594 (July-Oct.)
Minimum Capability (mw)	732 (June 1–10)	491 (May)
Annual Energy[a] (mln kwh)	12,500	2,900
Annual Capacity Factor[b] (%)	56	56
Cost per kw Firm Capacity[c] ($)	255	414
Cost per Installed kw ($)	107	363
Foreign Exchange Component (%)	75	63

[a] Mean-year flows.

[b] Capacity factor is taken here to mean average capability over a period as a percentage of maximum capability in that period—in the table on mean-flow year.

[c] Including transmission to Northern Grid (Lyallpur) in both cases, and including costs of dam in the case of Kunhar, but not in the case of Tarbela (which has been allocated to irrigation).

characteristics different from those of Low Mangla. Table 6-4 summarizes the power output in a mean year of High Mangla operated to a drawdown level of 1040 feet and, for comparative purposes, it indicates the mean year power characteristics of Low Mangla operated to a drawdown level of 1040 feet and of High Mangla operated to a minimum level of 1175 feet; a drawdown level of 1175 feet would mean that High Mangla would have approximately the same live storage as Low Mangla drawn down to 1040 feet.

Table 6-4 again illustrates the great fluctuation in the capability of the units between times when the reservoir is full and times when it is fully drawn down. This fluctuation is of course much reduced if a higher minimum reservoir level is maintained, as indicated by the last two columns. The last line of the table shows the proportion of total outflow in the mean year (natural flows plus storage releases) that would pass through the turbines. The figures indicate that, with Low Mangla, eight units will be sufficient to use all but 10 percent of the mean year discharges through the dam. The 10 percent of discharges that will not be passed through the turbines will occur chiefly in February-May when, because the reservoir is low, relatively small flows are required to keep the turbines running at 100 percent capacity factor. Maintenance of a substantially higher drawdown level would mean that more water could pass through the turbines at the time of minimum reservoir level, as illustrated by the third column of the table; in other words a higher proportion of total flows may then be usefully used for power generation.

Drawdown Levels at Tarbela and Mangla

The second set of questions studied concerned the drawdown levels at Tarbela and Mangla. Analysis of alternative drawdown levels is a logical follow-up to the preparation of the general outlines of a program of dam developments for helping to meet power and stored water requirements. It was pointed out above that, in the preparation of such a program, a drawdown level of 1332 feet at Tarbela was assumed. The main criteria used to develop the joint surface storage/power programs were requirements of rabi irrigation water and of electric power developed elsewhere in the Study; all alternatives considered had, in combination, to meet these requirements. But how valid are the requirements? Could greater benefit be derived from the reservoirs by, say, meeting the power requirements more fully and

TABLE 6-4
Comparison of High and Low Mangla Power Potential
(mean year)

	Low Mangla	High Mangla		
	Drawdown 1,040 feet	Drawdown 1,040 feet	Drawdown 1,175 feet	
No. and Size of Units (mw)	8 × 100	8 × 100	8 × 100	10 × 100
Maximum Capability (mw)	1,100 (Sept.)	1,180 (Aug.-Nov.)	1,180	1,480
Minimum Capability (mw)	360 (April)	360 (May 1–10)	950	1,190
Annual Energy (mln kwh)	5,800	6,250	7,800	8,100
Annual Capacity Factor (%)	60	60	75	63
Percent of Total Flows Used (%)	90	85	98	100

the irrigation requirements less fully? For storage dams are only one of the means that will be available in West Pakistan for meeting either requirement. Irrigation requirements may be met also by tubewells and power requirements may be met by thermal plants. Once the dams are constructed there will be a choice between drawing the reservoirs down fully each year, thereby making all the contents of the reservoir available for agriculture, and retaining some water in the reservoir throughout the year, thus maintaining a higher head on the turbines so that more power can be generated. Study of drawdown levels is thus essentially a study of marginal differences in the allocation of the storage capacity between power and irrigation.

The question of the level to which the reservoirs should be drawn down at the end of the winter season each year is of course only a specific case of the general problem of choosing release and filling patterns for operation of the reservoir. The criterion which is relevant in the choice of drawdown levels is no different from the criterion which should govern the choice of release pattern over each of the months (and shorter periods) in the year: the value of the last acre-foot of water released from the reservoir in any period should be equal to the expected value of the last acre-foot of water retained in storage at the end of the period. No attempt has been made here to carry out the kind of detailed operational study, involving comparison of agricultural and power benefits at different times over the year, which would be necessary to reach an optimum release pattern. However, the release pattern finally adopted by the irrigation consultant, as discussed in a later section of this Paper, was developed with a view to the competing claims of both power and irrigation. And, in practice, much the most important aspect of reservoir operation in West Pakistan from the point of view of long-term planning is the minimum level to which the reservoirs are drawn down each year.

The minimum level maintained at the reservoir will affect the amount of thermal generating capacity that has to be installed; Tables 6-3 and 6-4 indicated that the differences between minimum and maximum capability at Mangla will be very large and inspection of prospective load shows that this difference is very large compared to likely differences between the power loads in different months, so that the critical period on the power system (i.e. the time when generating reserves are at a minimum) will occur when the reservoirs are fully drawn down. Even though peak power load in the Northern Grid is at present about 50 mw higher in the winter than in the spring, the first two units at Mangla alone will suffice to bring the critical period in power-system capability from December to the spring. By comparison with changes in minimum reservoir level, changes in the pattern of releases from the reservoirs over the months of the year will have a relatively insignificant effect on the power system; such changes will normally alter only the amount of hydroelectric energy available at different times and hence the amount of energy that has to be generated thermally in different months. Therefore, attention in these studies has been focused on the costs and benefits to power and to agriculture of releasing more water over the year as a whole (according to a predetermined release pattern) as against retaining more water in the reservoir throughout the year. In other words, the approach is one of trying to get an indication of the direction in which the planned drawdown levels at Mangla and Tarbela should be shifted, if at all, in order to equalize the marginal benefits of the last few hundred thousand acre-feet gradually released over the course of the year and devoted to agriculture the irrigation requirements less fully? For storage dams are only one of the means that will be available in West Pakistan for meeting either requirement. Irrigation requirements may be met also by tubewells and power requirements may be met by thermal plants. Once the dams are constructed there will be a choice between drawing the reservoirs down fully each year, thereby making all the contents of the reservoir available for agriculture, and retaining some water in the reservoir throughout the year, thus maintaining a higher head on the turbines so that more power can be generated. Study of drawdown levels is thus essentially a study of marginal differences in the allocation of the storage capacity between power and irrigation.

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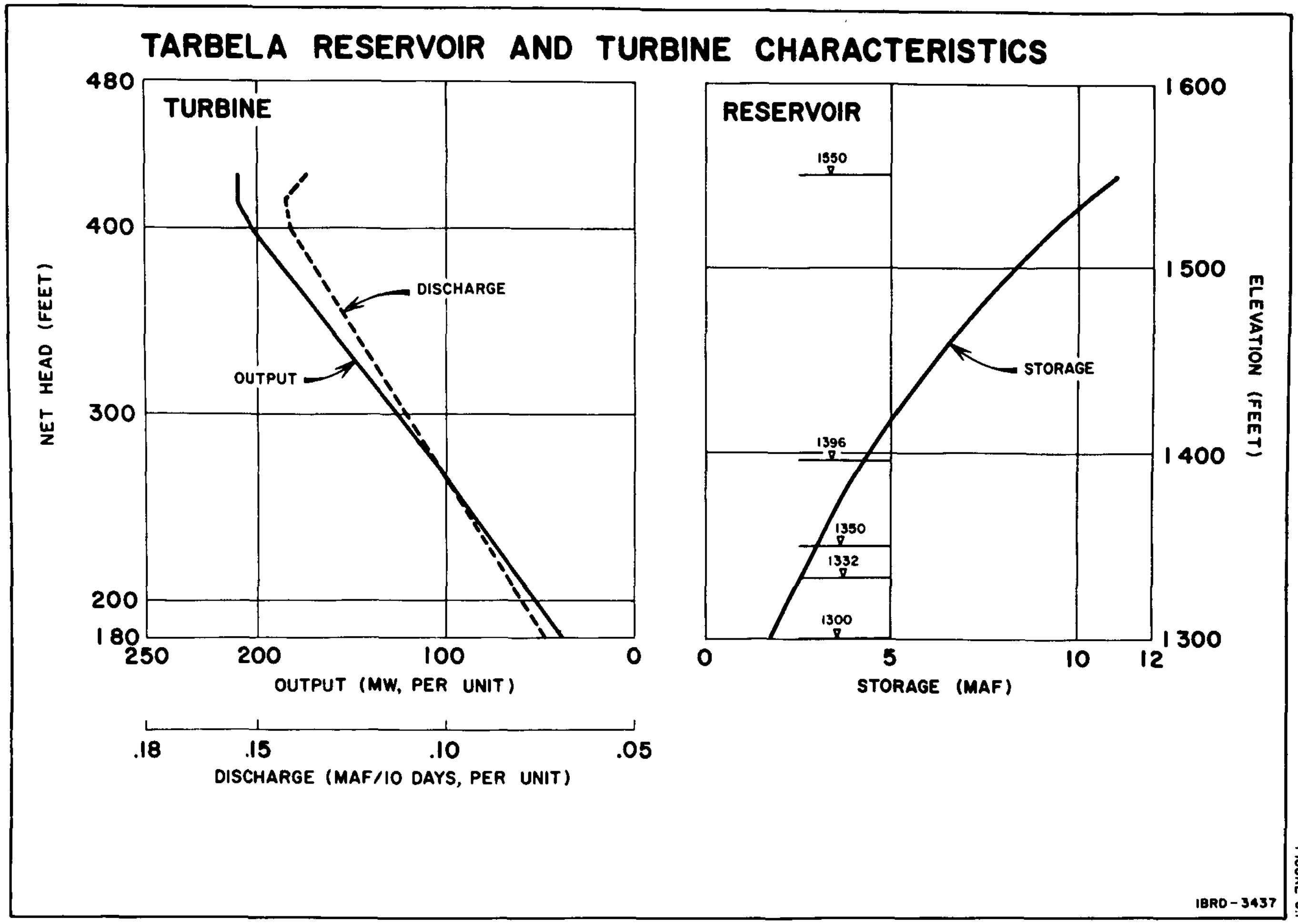

VOLUME III
FIGURE 6.1

The Study Group adopted a somewhat different approach. It devised alternative power programs, some on the assumption that, for instance, Tarbela would be held at 1332 feet, others on the assumption that it would be drawn down to 1300 feet, and with the aid of the computer model of the power system, it simulated the operation of the resultant power programs over the years and secured an indication of the differences in total system costs involved. The power consultant made calculations simply in terms of the amount of thermal equipment required to compensate for the lower drawdown level when all 12 units at Tarbela (or all eight at Mangla) were installed; in fact, of course, the 'saving' in thermal capability which results from maintaining the higher drawdown level builds up gradually over time as additional units are installed. But the value of the saving is probably greater than the 35-year annual charge figures imply because it takes the form of eliminating the need for relatively heavy capital outlay at the time the hydro units are installed; and thereafter the effect on the power program is to postpone continuously the need for further capacity additions by a year or two for as long as the higher minimum drawdown level is maintained. Though less important than the effect on the need for thermal capacity, the effect of a higher minimum drawdown level on the availability of energy at different times is significant and it is complex. Besides the main increase in energy available, which would occur around the critical period of lowest drawdown, there would also tend to be some increase in the late flood season as a result of reduced retention for storage, some increase in mid-winter as a result of higher reservoir levels, and some reduction in the later part of the winter as a result of reduced releases. The real value of these various changes in the availability of energy would depend on the monthly pattern of demand, and that value could change significantly as the result of adding additional hydro capacity which had a different monthly pattern of energy production. Computations with the aid of the simulation model resulted in a present-worth value of maintaining the higher drawdown level, taking into account the various capital, maintenance and fuel costs that would be saved and the years when they would be saved. Figures of this sort are cited in the Supplemental Papers which follow for Tarbela and Mangla.

Neither the 'annual charge per acre-foot of water' approach nor the approach on the basis of the power system simulation model comes to grips with the full complexity of the drawdown-level problem from the power point of view. The simulation approach results in a reasonable estimate of the present worth of the costs to Pakistan of drawing down to a lower minimum level rather than a higher one in every year of the Plan period. This is useful for comparison with the present worth of the benefits to agriculture from releasing the additional water each year for irrigation purposes. Such a comparison can be a valuable check on the validity of the storage program planned and it can be an indicator of the general order of priority that should be assigned to the claims of agriculture and power in the operation of the reservoirs. But the drawdown level on the reservoirs is not a question that has to be precisely defined before construction of the dams; it is open to decision each year. Yet, for the annual operating decision the power consultant's assessment of the benefit, though it is given as an annual value per acre-foot of water, is not very helpful either. It is clearly only an average value of the savings potentially available.

In practice, the savings to be had from maintenance of the higher drawdown level are likely to vary considerably among different years. In some circumstances

—say when additional hydroelectric capability is to be added to the system—the savings could be above average, and in other circumstances—say soon after additional base-load hydro units have come on line—the savings could be much less. Very much the same considerations will apply on the agricultural side: the benefits of drawing down Tarbela to 1300 feet rather than 1332 feet would likely be lower right after completion of the reservoir than say, 10 years later when the farmers have absorbed the water more fully and additional storage capacity is about to be added to the irrigation system. Moreover, wise decisions about the drawdown levels at Mangla and Tarbela that should be used for planning additions to system capability cannot be made without paying some attention to hydrological probabilities: what are the chances, for instance, that a year may have sufficiently high natural flows so that the higher drawdown level could be maintained without any detriment to agriculture? And what would be the consequences for power if a decision to maintain the higher drawdown level had to be reversed at the last moment because the year in question turned out to be one of low flows? These points are discussed somewhat more in the following Supplemental Papers.

Scheduling the Installation of Hydro Units

The third set of questions studied concerned the number of turbines to be installed at Mangla and Tarbela and the scheduling of their installation as well as that of two additional units which might be added at Warsak. Four tunnels are planned at Tarbela and it would be physically feasible to add a fifth; designs foresee four units on each tunnel that is dedicated to power uses, so it would be possible to install more than the 12 power units listed in Table 6-3 above. At Mangla, five diversion tunnels have been built and, although the fifth tunnel is being temporarily plugged with a steel bulkhead, it would be physically possible to install a penstock and enlarge the powerhouse so that it could accommodate 10 units instead of the presently envisaged eight listed in Table 6-4. At Warsak, inlet and outlet tunnels and space in the powerhouse already exist for addition of Units 5 and 6.

The length to which it is worth carrying hydroelectric development at a particular site depends on a large number of factors, but particular factors of interest are the heads that may be available and their variation over the year, the flows that may be available and their fluctuations over the year and among different years, the time pattern of demand for electricity, and the type and extent of generating capability available elsewhere on the power system. As long as Mangla and Tarbela retain a relatively large amount of live storage capacity, i.e., for at least the next 20 years, and as long as stored water is released broadly in accordance with the release patterns assumed here, the heads available at different times of the year will fluctuate widely. Moreover, flows will vary widely both over the year and among years, as pointed out at the beginning of this Supplemental Paper. Storage at Low Mangla operated to 1040 feet will transfer about 21 percent of mean-year flows from the kharif season to rabi and result in more than doubling even mean-year discharges in the winter release period; it will increase critical-year discharges in that period by about 130 percent. Nevertheless, under mean-year conditions, total discharges will only be sufficient to run as many as eight units at Mangla with about a 40-50 percent capacity factor in November through January. Under critical-year conditions, discharges would only be sufficient to sustain about a 40 percent capacity factor on eight units through that period. Installation of an

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The scheduling of additional units at the hydroelectric stations is considered in both a qualitative and a quantitative way in the following Supplemental Papers. The correct schedule will depend on the rate at which the load grows, on its pattern (i.e., how much hydro-peaking capability can be usefully absorbed in some months) and on the cost of alternative means of generation, particularly the cost of fuel for thermal generation. The power system simulation model was used to compare alternative schedules of unit installation for Tarbela, Mangla and Warsak.

Simulation of Reservoir Operation

To study the three sets of questions discussed above, it was necessary to have some means of simulating the operation of different sizes of reservoirs, drawn down to different minimum levels or to different release schedules. The irrigation consultant had developed a computer program as a means of testing the implications of different reservoir operating rules for the power capabilities and the energy output of the Tarbela and Mangla power plants. The Study Group wished to test the effect of various changes in assumption regarding system operation and to consider various additional alternative hydroelectric developments. For this purpose, it used a manual simulation approach basically very similar to the approach underlying the computer program but simplified in a number of relatively unimportant respects. The two approaches are described in detail and compared in Table 6-1, which also shows the more important of the data regarding the hydroelectric stations' capabilities and energy outputs which were drawn from the reservoir operation studies for use in the power system simulation model. This Table also includes the main data used regarding the hydroelectric potential of Kunhar and Warsak; figures for these plants were taken directly from the power consultant and from Harza.

In the Study Group's manual simulation the operation of Mangla and Tarbela Reservoirs was simulated by 10-day periods throughout the year. A fixed release pattern was used. Reservoir content at the beginning of each 10-day period was derived by subtracting releases during the previous 10-day period from the reservoir content at the beginning of that period (or, in the filling period, adding net inflows during the period to the reservoir content at the beginning of the previous period). The elevation of the reservoir at this time could then be read from a curve relating reservoir content to reservoir elevation. Addition of releases to natural flows in a 10-day period (or subtraction of amount required for filling during filling period) indicates the total outflow through the dam to be expected in this 10-day period, and comparison of this with the discharge capacity of the number of turbines assumed installed indicates the extent to which the turbines can be operated during the 10-day period in question. The resultant 'Operation Factor' (or available discharge as a percent of maximum discharge capacity[1]) can be multiplied by the maximum amount of energy that would be available from the turbines if they were operated continuously through the 10-day period at maximum load, given the head available, in order to derive a figure for the actual amount of energy available in the period.

The Release Pattern

From this brief description of the simulation of reservoir operation, it is clear that the release pattern used will affect the head available on the turbines at different times of the year and it will also affect the amount of discharge in any 10-day period. A change in release pattern may therefore affect both the peak capability of the units and the energy that they can produce in a period. In practice, as pointed out previously in the discussion regarding drawdown levels, where the capability of the hydroelectric stations will fluctuate over the year as greatly as it will at Mangla and Tarbela, changes in either capability or energy output of the units during the bulk of the release period will affect only the amount of energy that has to be generated thermally; they will not affect the amount of thermal capability that must be installed in order to meet loads.

For the purposes of its analyses, the Study Group adopted fixed release patterns for Mangla and Tarbela. A 'fixed' release pattern means that a fixed proportion of live storage is assumed to be released in a period in addition to all natural flows during that period. An alternative approach to the regulation of a storage reservoir is what might be called the 'fixed total outflow' approach: stored water is drawn upon as necessary to supplement natural flows and bring total outflow through the dam up to some predetermined target in any period. The 'release pattern' approach has the disadvantage of being inflexible; it can result in the squandering of surface water by releasing too much in some months when river inflows are above average. The 'fixed total outflow' approach, on the other hand, can result in the premature emptying of the reservoir, so that irrigation supplies and generating capacity are severely curtailed at the end of the release season. In practice, it should be possible to work up some combination of these two approaches—specifying, for instance, the end-of-period reservoir content implied by the fixed release pattern as a minimum which might, however, be exceeded as a result of releasing less stored water in the event that natural river flows in a particular period are above average.

After comparison between a large number of alternatives, the fixed release patterns adopted for the Study Group's power studies were in fact those finally recommended by the irrigation consultant. These release patterns were derived primarily with a view to the needs of agriculture for supplies of surface irrigation water. They were developed mainly on the principle of spreading surface water deficiencies in a

[1] The Operation Factor cannot of course be greater than 100, for there is a limit to the amount of water that can be discharged through the turbines at any given head. If more water must be passed through the dam (e.g., to meet downstream irrigation requirements) then the excess over the discharge-capacity of the turbines must be passed by the spillway or by the irrigation release valves.

year of low rabi flow[1] evenly throughout the release period as a proportion of the total irrigation requirement, the deficiencies being met by temporary overpumping of groundwater in certain canal commands. The attempt was made to concentrate regular pumping of recharge to the groundwater aquifer in the period October through March, when the combined power capabilities at Mangla and Tarbela will be greater than they will be at the end of the release season in April-May. Somewhat heavier reliance on groundwater supplies for irrigation in the early part of the winter than in the later part has the added advantage of keeping up the reservoir level and the head on the turbines a little higher than would otherwise be possible.

Since these release patterns have been developed on the basis of low rabi flow-years, they indicate approximately the maximum amount of releases that IACA considers to be warranted in the early part of the release season and hence the minimum reservoir levels that should be maintained at different dates through the winter. Thus the estimates of the time pattern of hydroelectric capability that correspond to this pattern of minimum reservoir levels should be conservative. In years when natural flows are greater than those of the low rabi year the actual capabilities should be greater.

Table 6-7 shows the final Tarbela and Mangla release patterns adopted by the irrigation consultant and compares them with those used by Harza in some of their computer studies. IACA estimates that the seasonal demand for storage at Mangla will be concentrated in the six months from October to March, with high peaks in October and February. At Tarbela, the period of storage demand would normally be from November to the beginning of April in 1975 and to the end of April by 1985. The comparative figures for the Tarbela release pattern in Table 6-7 illustrate the emphasis that IACA places on using groundwater pumping at the beginning of the rabi season to reduce the need for storage releases at that time and thus to maintain a higher reservoir level until the end of February. Because of the great variability in flows on the Indus and the consequent possibility that storage releases could be required even up to the middle of May, IACA also recommends retention of about 5 percent of live storage at Tarbela through the end of April as an insurance against low spring flows. As regards Mangla, IACA has a somewhat higher release than Harza at the beginning of the rabi season in October, but this results from the combination of low natural flows on the Jhelum and the Chenab in that month and high irrigation demands during the overlap of kharif and rabi crops. IACA estimates show that, even with a 23 percent release in October, potential deficiencies that have to be made up by pumping are large compared to those of other months.[2] During February and March, the peak crop water requirements occur. As regards filling of the reservoirs, the irrigation consultant's

[1] The irrigation consultant considered that critical-year flow conditions were too severe for use in developing rules for reservoir operation and therefore IACA composed a synthetic stream-flow sequence, entitled 'low rabi year' specifically for this purpose. The lowest 50 percent of the monthly flow on each river in October to May during the 41-year period of record were averaged and the resultant flows were adopted as low rabi flows. Low rabi flows in the October-May period on the Jhelum were taken as 9.15 MAF compared with 8.59 MAF critical year flows (1954/55) and 10.88 MAF mean-year flows. Low rabi flows on the Indus (at Attock) in the same months were taken as 23.61 MAF compared with 17.84 critical year flows (1954/55) and 26.09 MAF mean-year flows.

[2] IACA's Comprehensive Report, Volume 5, Annexure 7—Water Supply and Distribution (May 1966), p. 105.

TABLE 6-7
TARBELA AND MANGLA RELEASE PATTERNS
(% of live storage: positive figures = releases; negative figures = storage)

	Mangla		Tarbela	
Month	Harza	IACA	Harza	IACA
October	17	23	8	0
November	16	15	10	8
December	14	10	10	11
January	14	10	15	21
February	20	24	23	26
March	18	18	20	19
April	−12	0	14	10
May	−18	−24	−30	5
June	−23	−36	−50	−45
July	−27	−31	−10	−55
August	−20	−9	−10	0
September	0	0	0	0

studies indicated that the balance between flows and downstream irrigation demands in the spring was such that filling could not be reliably expected to begin before May at Mangla and June at Tarbela—or one month later than Harza had projected. However, once filling was begun it might proceed more rapidly.

Hydrological Uncertainty and Peaking Capability

The capabilities and energy outputs of the hydroelectric units at Tarbela and Mangla, as presented in this Supplemental Paper, relate to mean-year flow conditions; and this is indicative of an important difference between the approaches to hydroelectric decisions adopted by the Study Group and its consultants. Both the Study Group and its consultants adopted mean-year flow conditions for developing the figures on hydroelectric capabilty and hydroelectric energy which were used in analyses of system dispatch; equally both the Study Group and its consultants adopted critical year conditions for developing figures regarding the firm capability of the hydroelectric units for use in planning additions to system capability. However, the Study Group took the view that it would not be necessary to restrict the peaking capability of the units whereas its consultants had assumed that peaking would be restricted to certain fixed levels, and this makes for a significant difference in assessment of capability in the critical year at the time of system minimum capability.

Peaking at these multipurpose reservoirs essentially involves storing some water over a day and then releasing a large quantity in a short space of time, as contrasted with maintaining an even discharge over the day. With the even discharge, the turbines can be run to produce a steady flow of energy but at low load; with the concentrated discharge, the steady flow of base-load energy will be reduced but the units will be able to make a larger contribution to meeting peak power loads of short duration. The sharp fluctuations in discharges which occur in connection with peaking operation of the units could result in surges downstream which might cause undesirable scouring or other damage.

For the purpose of their studies, the consultants assumed a 20 percent limit on peaking at Mangla and a 30 percent limit on peaking at Tarbela—which means, in other words, that peak discharges could not be more than 20 percent (or 30 percent) in excess of average discharges, or, in terms of power-output, that average load on the turbines could not be less than 80 percent (or 70 percent) of peak load on them. Generally speaking, under mean-year conditions, with 12 units installed at Tarbela with a drawdown level of 1332 feet and eight units installed at Mangla with a drawdown level of 1040 feet, this limit only becomes effective in the early part of the release period, i.e., October-February, the season when flows are relatively low. However, under critical year conditions, the limit can become effective much later in the year, even at the time of system minimum capability. Table 6-8 illustrates this point. The capabilities given reflect directly the heads available on the turbines at the beginning of each 10-day period, without any reduction on account of lack of flows. The capacity factors indicate available flows as a percentage of the flows that would be required to run the units continuously at the loads listed for each period. The effect of introducing the limits on peaking used by the consultants would be to restrict these capacity factors to a minimum of 80 percent for Mangla and 70 percent for Tarbela, by scaling down the peak loads to the degree necessary. The need for this scaling down would arise, for instance, in the first 10 days of May at Tarbela during the critical year flows: the peak load of 876 mw could be sustained for only 66.8 percent of the time—or, in other words, an average load of about 585 mw. Observance of the 30 percent limit on peaking would mean that peak load could only be 30 percent above this or about 760 mw.

It may well be, of course, that the appetite of the power system for peak power supplies will generally be too small (given the size of loads, the importance of Mangla and Tarbela capabilities in the overall system, and the amount of other generating capability in the system) to make it worthwhile running Tarbela and Mangla units for peaking service. However, there does not appear to be any physical obstacle to peaking with them, and so, for the purpose of planning capacity additions, the Study Group assumed that full peaking capacity would be available at Mangla and Tarbela. Given this assumption and the assumption of a fixed release pattern, the capabilities of the hydro units are identical in the critical year

TABLE 6–8
EFFECT OF CRITICAL AND MEAN-YEAR FLOWS ON POWER-PRODUCTION AT TARBELA AND MANGLA AT TIME OF SYSTEM MINIMUM CAPABILITY

	Mangla (8 Units) 1,040 feet[a]				Tarbela (12 Units) 1,332 feet			
	Mean-Year Flows		Critical Year Flows		Mean-Year Flows		Critical Year Flows	
	Peak Load (mw)	Capacity Factor	Peak Load (mw)	Capacity Factor	Peak Load (mw)	Capacity Factor	Peak Load (mw)	Capacity Factor
Mar. 1–10	672	100.0	672	71.5	1,608	66.2	1,608	59.6
Mar. 11–20	584	100.0	584	92.5	1,476	74.0	1,476	67.6
Mar. 21–31	512	100.0	512	100.0	1,296	84.4	1,296	74.0
Apr. 1–10	400	100.0	400	100.0	1,128	74.0	1,128	61.9
Apr. 11–20	400	100.0	400	100.0	1,044	81.4	1,044	68.4
Apr. 21–30	400	100.0	400	89.2	936	100.0	936	73.3
May 1–10	400	100.0	400	66.6	876	100.0	876	66.8
May 11–20	536	100.0	536	66.2	828	100.0	828	80.1
May 21–31	664	100.0	664	64.4	768	100.0	768	100.0

[a] The Mangla capabilities shown here may be somewhat too high and the capacity factors slightly too low because they are based on the Study Group's reservoir simulation, which assured a low tailwater level. The text remains correct.

and the mean year, as implied by Table 6-8, because they are dependent only on available head. However, firm capacity as used in the Study Group's investigations for capacity planning does still differ in one respect from capacity as used in the Study Group's system dispatches: firm capacity is taken as system capacity in the minimum 10-day period whereas the dispatch is performed on the basis of average capacities in each month.

The only restriction on peaking at Mangla and Tarbela that can now be foreseen is in connection with the requirements of the Upper Jhelum Canal, which will be supplied from Mangla; but the requirements of this canal are small compared to the discharges of eight units at Mangla and so, although allowance was made for this in the Study Group's analyses, it does not in fact alter the conclusions drawn above. Mangla will probably have to be operated in such a way as to maintain a uniform flow in the Upper Jhelum Canal; flows in excess of this amount released during peaking periods or during periods of high flow will simply return to the Jhelum River by way of the new Bong Escape. The dam sites consultant considers that the regulation afforded naturally in the Jhelum River Channel above Rasul Barrage, together with small permissible fluctuations (less than six inches) of the barrage pond will be sufficient to prevent any foreseeable degree of peaking at Mangla from interfering with steady irrigation withdrawals at Rasul Barrage to the Lower Jhelum Canal and Rasul-Qadiribad Link Canal. Therefore, for purposes of the power system simulation model, the units at Mangla were divided into two groups—those whose discharges would be required to meet the requirements of the Upper Jhelum Canal so that they must be run continuously on base load and the remainder (generally five or six out of a total of eight units) which could be peaked to an unrestricted degree. At Tarbela, there would not appear to be any danger that peaking, via the creation of sudden surges in the river, would cause damage to downstream structures or interfering with irrigation supplies; therefore, it was assumed that the Tarbela units could be peaked as and when necessary.

Another aspect of hydrological uncertainty is sufficiently important to deserve comment. This concerns the use of tubewells for making up deficiencies in irrigation supplies in poor hydrological years. The irrigation consultant envisages temporary overpumping in years of low flow which would be balanced by the additional recharge to the groundwater aquifer in years of high flow. The power consultant estimated the additional pumping load that would be involved in a critical hydrological year. Table 6-9 shows the figures on a Provincewide basis for the two key years 1975 and 1985. The power development programs discussed in Volume I do not include explicit provision for covering these loads, since the power programs are all based on a fairly comfortable reserve-criterion: 12 percent of thermal capability and 5 percent of hydro capability. It is assumed that these occasional additional pumping loads would be met from reserve generating capacity. Most of the power programs considered include systemwide reserves in the order of 250 mw

TABLE 6-9
ADDITIONAL PUMPING LOAD (MW) IN CRITICAL YEAR
(mw)

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
1975	12	35	32	26	30	34	5	0	55	44	14	8
1985	49	68	215	87	130	124	15	0	55	72	48	36

in 1975 and 500 mw or above in 1985, so that they would seem to be capable of coping with any additional pumping requirements resulting from low flows. The fact that the additional pumping requirements would occur at the same time as the shortage of hydro energy should result only in the need to generate more energy thermally, given the relatively high capacity factors on the hydroelectric units indicated in Table 6-8 even for critical year conditions.

Reservoir Siltation and its Effects on Power

It was pointed out at the beginning of this Supplemental Paper that the live storage capacity of Tarbela is likely to be depleted rather rapidly as a result of siltation. However, this factor has not been taken into account in the Study Group's simulation of reservoir operation. It has been neglected partly because there is uncertainty about the rate of siltation and about the precise effect that it will have on power capabilities and energy production; also the effects that can be anticipated are not likely to be very significant within the first 10 to 20 years of the life of the reservoir.

The effects of siltation on Tarbela as a power producer will depend upon two important factors—the pattern of deposition of the sediment and the way in which the resulting changes in the reservoir affects the choice between releasing more water for irrigation and retaining it to maintain a higher head at the time of minimum reservoir level. Sediment patterns depend on many factors: such as reservoir shape, average detention time, grain size distribution of the sediment, the temperature of the reservoir water relative to the temperature of the inflowing water, the reservoir depth at the times heavily sediment-laden flows enter the reservoir, the depth of annual reservoir drawdown level, and the timing and rate of discharge through outlets near the bottom of the reservoir relative to river inflows. The dam sites consultant assessed the situation at Tarbela and reached the conclusion that the sand component of the sediment load (about 60 percent of the total) would tend to settle quickly and be deposited near the upper end of the reservoir at the then existing level while the silt (the remaining 40 percent) would settle more slowly and be deposited in thinner, more extensive layers mantling the bottom and sides of the reservoir. In time, as reservoir sedimentation progressed, the sand-front would tend to advance, delta-style, towards the dam.

During the first 10 to 20 years of Tarbela's life, the main effect of siltation on power is likely to be only a gradual reduction of the energy output in the winter release period—which will be compensated by somewhat greater use of then existing thermal equipment. The winter period is affected because rabi flows will have to be reduced in line with storage capacity. During the first 10-20 years, according to an estimate by Chas. T. Main, about 50-60 percent of the sediment retained in the Tarbela Reservoir will settle in the live storage area; live storage would consequently be reduced from 8.6 MAF initially (with drawdown level of 1332 feet) to about 7.4 MAF after 10 years and 6.0 MAF after 20 years. The simulation model developed by IACA allows for the effect of reduced releases on the output of the turbines. Some of their computer runs also give an indication of the order of magnitude of the siltation effect. They show, for instance, that the mean-year energy output of 12 units at Tarbela might be reduced about 4 percent between 1980 and 1985, or by about 250 million kwh. The reduction occurs entirely in the release period November-May, and primarily in January and February; energy is reduced in each of these months by about 60 million kw. The computer print-outs also show a fall in the peaking capability of the units particularly in January and February when the reduction is as much as 100 mw. However, this sharp reduction results mainly from the special restriction on peaking assumed in the computer simulation of reservoir operation and discussed previously.

Over the longer term, the effect of siltation on the power capabilities of the Tarbela units will be more positive because it will involve a gradual increase of the minimum drawdown level on the reservoir. Siltation in the lower levels will tend to raise the minimum levels to which it is physically possible to draw the reservoir down—to about 1332 feet within 30 years of the completion of the project and 1400 feet within 40 years of completion, according to the dam sites consultant. However, even before these dates are reached the effects of siltation may be such as to prompt a gradual increase in the minimum levels to which the reservoir is drawn down. In the first place, as siltation proceeds, the gain in irrigation supplies obtainable by drawing down to a lower minimum level will gradually fall. Table 6-10 illustrates this point as it is presented in the surface storage discussion in Volume I. In 1985, 10 years after Tarbela is completed, about 0.6-0.7 MAF of live storage capacity would be lost to agriculture by drawing down to 1332 feet rather than 1,300 feet; however, after the passage of another 15 years (in 2000), only about 0.1 MAF of live storage would be lost to agriculture by similar operation. At the same time there does not appear to be any particular reason why the power benefits of maintaining the higher drawdown level should fall. Hence the net value of keeping up the minimum reservoir level would seem likely to increase over the years. There is also another factor which may favor holding the reservoir above the physically feasible minimum level. Once the dead storage volume is filled with sediment—and it is recognized that this could happen earlier than presently projected (2005), as a result of higher than expected sediment flows or unforeseen shifts in the sediment deposited in the reservoir—the water discharged from the reservoir when it is fully drawn down will probably become heavily sediment-laden. The abrasive effects of sediment-laden flows on the turbines might become sufficiently severe to justify changing the minimum operating level of the reservoir so as to maintain a detention pond in which the heavier sediment particles would settle. Thus, over the longer term, the minimum capabilities of the Tarbela units would increase and the availability of power from the project should be much more evenly spread over the year than it will be initially; the extent to which it will be necessary to place the units in peaking service in the winter months will depend on available flows in that season; these flows in turn will depend on the development of upstream storage.

TABLE 6-10
THE DEPLETION OF TARBELA LIVE STORAGE CAPACITY
(capacity in MAF)

Drawdown Level (feet)	Initial (1975)	1985	2000
1300	9.3	7.9	5.6
1332	8.6	7.3	5.5
1350	8.2	6.9	5.4
1400	6.7	6.1	5.0
1500	2.7	2.5	2.45

APPENDIX TABLE 6-1

MONTHLY RUNOFF SUMMARY—INDUS RIVER AT ATTOCK (MAF)

	Rabi			Kharif						Rabi			
Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Yearly Total
1922	2.02	2.14	3.02	4.83	8.09	22.79	22.99	21.01	12.14	3.81	2.31	2.05	107.20
23	1.95	2.09	2.91	5.53	9.06	18.06	18.78	23.58	9.31	3.64	2.58	2.04	99.53
24	1.63	1.77	2.82	5.68	5.75	14.89	32.24	25.28	11.29	3.95	2.66	2.16	110.12
25	2.10	1.67	2.02	3.60	6.30	17.18	22.48	15.48	7.43	3.38	2.66	2.13	86.43
1926	1.78	1.34	2.06	3.37	6.71	10.86	18.74	23.38	12.11	4.36	2.13	1.75	88.59
27	1.49	1.30	1.76	3.08	5.95	8.65	20.73	19.44	6.99	3.28	2.10	1.88	76.65
28	1.58	2.18	3.47	5.39	11.17	18.55	22.72	16.48	7.99	3.05	2.14	1.89	96.61
29	1.55	1.27	2.38	3.47	6.04	13.65	18.51	25.72	9.15	4.29	2.70	2.33	91.06
30	2.31	2.25	4.18	6.48	10.04	16.98	29.76	17.34	7.67	3.59	2.40	1.89	104.89
1931	1.77	1.68	2.15	4.17	7.59	13.84	20.49	21.15	9.33	4.77	2.25	1.98	91.17
32	1.93	1.74	3.08	4.07	5.83	14.18	25.89	20.70	8.02	3.81	2.10	1.99	93.34
33	1.62	1.45	2.39	3.55	7.38	17.46	24.68	22.24	9.37	4.22	2.09	1.79	98.24
34	1.61	1.42	1.83	3.32	4.46	18.22	25.39	19.22	9.20	4.17	2.14	1.80	92.78
35	1.58	1.79	2.53	4.13	7.75	11.95	24.93	21.77	8.14	3.91	2.29	1.92	92.69
1936	1.65	1.61	3.40	4.07	12.09	20.29	19.91	16.85	10.41	2.95	1.92	1.80	96.95
37	1.65	1.58	2.03	4.24	11.22	16.99	19.36	16.01	8.18	2.33	2.04	2.38	88.01
38	1.45	1.26	2.35	5.18	15.31	17.65	20.55	19.94	7.64	3.20	1.99	1.67	98.19
39	1.59	2.25	5.58	6.22	12.30	19.59	23.15	16.88	10.52	4.04	2.07	1.75	105.94
40	1.56	1.46	1.78	4.11	7.70	17.47	20.99	14.94	6.08	2.39	1.77	1.51	81.76

1941	1.37	1.26	1.78	4.05	13.47	18.37	18.36	18.14	6.88	3.82	1.84	1.81	91.15
42	2.08	2.31	3.22	5.07	10.50	14.94	28.03	22.22	10.31	3.55	2.31	2.11	106.65
43	2.11	1.71	2.96	4.39	6.17	15.44	25.38	20.99	9.91	3.53	2.14	1.80	96.63
44	1.75	1.60	1.82	4.08	7.63	10.88	21.90	22.10	8.02	3.34	2.09	1.88	87.09
45	1.87	1.51	2.25	4.97	7.39	17.27	27.62	18.74	10.28	3.61	2.17	1.94	99.62
1946	1.84	1.68	2.08	5.30	8.61	12.58	19.34	20.71	7.03	3.75	1.97	1.61	86.50
47	1.54	1.50	1.79	2.88	7.49	12.99	15.69	18.34	9.12	2.74	1.71	1.51	77.30
48	1.43	1.28	1.96	3.79	7.56	9.37	20.94	23.61	9.42	4.21	1.99	1.77	87.33
49	1.76	1.61	2.70	5.16	12.70	12.91	24.33	18.24	9.40	3.68	1.89	1.66	96.04
50	1.67	1.65	1.93	3.40	9.11	19.35	26.95	21.41	8.47	2.97	1.83	1.54	100.28
1951	1.76	1.60	2.00	2.29	7.41	10.24	16.11	19.34	5.31	3.05	1.75	1.43	72.29
52	1.37	1.38	1.96	4.38	6.99	17.98	22.70	17.84	7.22	3.03	1.76	1.48	88.09
53	1.42	1.27	1.81	3.55	9.17	17.51	22.89	16.66	8.07	3.05	1.96	1.69	89.05
54	2.02	2.22	2.89	2.78	8.61	17.73	19.84	18.86	9.43	3.47	1.89	1.57	94.31
55	1.40	1.21	1.64	1.97	4.71	14.61	17.16	23.11	9.67	3.55	1.90	1.68	82.61
1956	1.48	1.30	2.47	4.55	12.05	15.93	24.51	20.78	9.23	4.58	2.23	1.85	100.96
57	1.63	1.56	2.32	4.70	6.47	15.19	22.92	17.22	5.95	3.30	2.46	2.29	86.01
58	1.77	1.36	2.12	5.09	6.30	13.65	28.40	18.91	9.50	3.82	2.28	2.61	95.81
59	2.31	2.47	3.61	5.95	9.24	19.53	24.94	23.36	5.89	6.47	3.53	2.53	109.83
60	1.74	1.61	2.94	5.07	9.62	16.80	26.57	22.02	9.58	3.24	1.88	1.67	102.74
1961	1.63	1.46	1.56	3.78	6.43	14.03	23.06	17.35	12.42	3.84	2.17	1.89	89.62
62	1.63	1.39	1.61	3.00	4.76	11.90	17.34	17.40	7.22	2.56	1.87	1.79	72.47
63	1.55	1.25	2.19	3.60	8.67	19.30	21.00	18.40	7.62	2.67	1.89	1.65	89.79

Note: Gauge heights obtained from Irrigation Department. Discharge computed by TAMS and Surface Water Circle using rating curve based on 1948–61 current meter discharge measurements. Tabulation by Harza Engineering Company Inc.

APPENDIX TABLE 6-2

Critical and Mean Year Flows on Jhelum at Mangla and on Indus at Tarbela

(MAF)

		Jhelum		Indus	
		Critical	Mean	Critical	Mean
Jan.	1–10	.127	.168	.365	.355
	11–20	.122	.168	.346	.350
	21–30	.121	.201	.315	.342
Feb.	1–10	.127	.245	.303	.347
	11–20	.112	.281	.293	.358
	21–30	.113	.307	.293	.372
Mar.	1–10	.181	.438	.303	.394
	11–20	.291	.510	.335	.416
	21–30	.371	.610	.365	.492
Apr.	1–10	.558	.765	.444	.584
	11–20	.616	.878	.496	.645
	21–30	.50	.986	.518	.810
May	1–10	.765	1.110	.568	1.022
	11–20	.80	1.220	.70	1.348
	21–30	.82	1.260	.962	1.913
June	1–10	.915	1.270	1.632	2.955
	11–20	1.04	1.290	3.215	3.765
	21–30	.894	1.325	3.96	4.120
July	1–10	.968	1.345	3.88	5.170
	11–20	1.0	1.245	4.48	5.420
	21–30	.838	1.222	4.38	5.640
Aug.	1–10	1.155	1.140	4.88	5.910
	11–20	1.215	1.000	6.05	5.210
	21–30	1.153	.830	5.84	4.160
Sept.	1–10	.782	.670	4.88	3.095
	11–20	.558	.540	3.235	2.235
	21–30	.456	.436	1.735	1.545
Oct.	1–10	.325	.340	1.44	1.087
	11–20	.283	.278	.953	.840
	21–30	.253	.237	.689	.653
Nov.	1–10	.243	.197	.548	.572
	11–20	.205	.173	.526	.506
	21–30	.175	.159	.496	.456
Dec.	1–10	.173	.155	.466	.418
	11–20	.152	.165	.426	.400
	21–30	.141	.157	.386	.380
		18.548	23.321	60.703	64.285

APPENDIX TABLE 6-3

CONSULTANTS' COMPUTER SIMULATION OF RESERVOIR OPERATION—MANGLA AND TARBELA, 1985—MEAN YEAR FLOWS

	Mangla (8 Units)							Tarbela (12 Units)						
	Reservoir Content (MAF)	Storage Release (MAF)	Peaking Capacity (mw)	Max Aval Energy (kwh × 10⁶)	Unused Flow (MAF)	Reduction Factor	Available Head (Ft)	Reservoir Content (MAF)	Storage Release (MAF)	Peaking Capacity (mw)	Max Aval Energy (kwh × 10⁶)	Unused Flow (MAF)	Reduction Factor	Available Head (Ft)
Oct. 1	4.560	0.169	709.6	142.74	0.000	0.662	356.7	7.300	−0.	2,151.1	414.24	0.000	0.888	430.9
Oct. 11	4.391	0.150	689.0	140.54	0.000	0.651	353.9	7.300	−0.	1,667.8	321.86	0.000	0.688	431.9
Oct. 21	4.241	0.182	662.4	137.13	0.000	0.635	351.3	7.300	0.073	1,444.6	278.74	0.000	0.596	432.4
Nov. 1	4.058	0.196	610.5	127.38	0.000	0.593	348.2	7.227	0.146	1,424.8	275.01	0.000	0.588	431.2
Nov. 11	3.862	0.196	564.8	118.29	0.000	0.556	344.8	7.081	0.219	1,426.7	275.62	0.000	0.589	428.8
Nov. 21	3.666	0.192	529.8	110.98	0.000	0.529	341.5	6.862	0.219	1,313.4	254.17	0.000	0.542	425.5
Dec. 1	3.475	0.210	545.6	113.81	0.000	0.552	337.9	6.643	0.241	1,267.9	245.97	0.000	0.523	422.0
Dec. 11	3.265	0.210	555.7	114.58	0.000	0.572	333.3	6.402	0.241	1,216.3	236.99	0.000	0.502	417.6
Dec. 21	3.055	0.210	539.6	109.72	0.000	0.566	328.7	6.161	0.248	1,169.8	229.97	0.000	0.483	411.1
Jan. 1	2.845	0.210	548.9	111.27	0.000	0.589	323.6	5.913	0.336	1,266.8	250.84	0.000	0.527	403.5
Jan. 11	2.636	0.210	540.5	109.32	0.000	0.593	318.6	5.577	0.343	1,256.3	248.32	0.000	0.534	396.1
Jan. 21	2.426	0.210	576.2	116.34	0.000	0.650	313.0	5.234	0.343	1,226.1	242.08	0.000	0.535	388.4
Feb. 1	2.216	0.237	663.1	133.76	0.000	0.772	306.5	4.891	0.511	1,513.5	298.16	0.000	0.685	379.1
Feb. 11	1.979	0.237	696.5	140.57	0.000	0.843	299.2	4.380	0.511	1,489.8	292.25	0.000	0.725	365.1
Feb. 21	1.742	0.233	707.7	142.81	0.000	0.894	291.6	3.869	0.511	1,451.7	284.00	0.000	0.765	348.0

Mar. 1	1.509	0.237	752.9	157.40	0.059	1.000	282.6	3.358	0.489	1,395.4	272.46	0.000	0.786	334.4
Mar. 11	1.272	0.237	712.4	170.98	0.052	1.000	273.3	2.869	0.489	1,362.3	264.21	0.000	0.839	317.6
Mar. 21	1.035	0.233	668.0	160.32	0.166	1.000	263.0	2.380	0.482	1,401.2	269.44	0.000	0.940	302.8
Apr. 1	0.803	0.123	620.2	148.84	0.232	1.000	252.0	1.898	0.423	1,359.8	260.61	0.007	1.000	287.6
Apr. 11	0.679	0.123	588.6	141.27	0.357	1.000	244.7	1.475	0.409	1,216.5	233.67	0.083	1.000	270.1
Apr. 21	0.556	0.169	553.8	132.92	0.525	1.000	236.6	1.066	0.482	1,075.1	258.03	0.101	1.000	252.8
May 1	0.388	−0.502	528.6	115.90	0.027	1.000	230.7	0.584	0.255	929.0	222.97	0.160	1.000	235.1
May 11	0.889	−0.274	635.7	152.56	0.281	1.000	255.6	0.328	0.328	838.6	201.25	0.607	1.000	224.1
May 21	1.163	−0.274	683.9	164.13	0.302	1.000	266.7	−0.000	−0.	721.9	173.25	0.911	1.000	210.0
June 1	1.436	−0.456	735.8	176.60	0.107	1.000	278.7	0.000	−1.095	723.3	173.60	0.855	1.000	210.2
June 11	1.892	−0.502	801.8	192.44	0.059	1.000	293.9	1.095	−1.095	1,049.0	251.75	1.486	1.000	249.6
June 21	2.394	−0.502	865.5	207.73	0.068	1.000	308.0	2.190	−1.095	1,385.8	332.60	1.707	1.000	290.7
July 1	2.896	−0.456	916.2	219.89	0.118	1.000	319.7	3.285	−1.460	1,680.7	403.37	2.271	1.000	323.9
July 11	3.352	−0.456	962.7	231.05	0.006	1.000	331.1	4.745	−1.460	2,072.0	497.29	2.390	1.000	366.9
July 21	3.808	−0.410	993.8	238.51	0.015	1.000	339.5	6.205	−1.095	2,396.0	575.04	2.823	1.000	402.2
Aug. 1	4.218	−0.342	1,024.6	213.79	0.133	1.000	347.1	7.300	−0.	2,422.6	581.41	4.263	1.000	422.5
Aug. 11	4.560	−0.	1,041.4	249.94	0.202	1.000	351.0	7.300	−0.	2,422.6	581.41	3.565	1.000	422.4
Aug. 21	4.560	−0.	1,051.7	252.41	0.038	1.000	352.7	7.300	−0.	2,422.6	581.41	2.542	1.000	423.0
Sept. 1	4.560	−0.	1,060.8	219.79	0.000	1.000	354.3	7.300	−0.	2,422.6	581.41	1.468	1.000	424.8
Sept. 11	4.560	−0.	877.3	177.37	0.000	0.822	355.6	7.300	−0.	2,422.6	581.41	0.620	1.000	426.9
Sept. 21	4.560	0.068	824.0	166.32	0.000	0.771	355.9	7.300	−0.	2,422.6	500.94	0.246	1.000	429.1

Mangla Drawdown: 1075 feet. Tarbela Release Pattern: October 8, 1965.

APPENDIX TABLE 6-4

CONSULTANTS' COMPUTER SIMULATION OF RESERVOIR OPERATION—MANGLA AND TARBELA, 1985—CRITICAL YEAR FLOWS

	Mangla (8 Units)							Tarbela (12 Units)						
	Reservoir Content (MAF)	Storage Release (MAF)	Peaking Capacity (Mw)	Max Aval Energy (Kwh × 10^6)	Unused Flow (MAF)	Reduction Factor	Available Head (Ft)	Reservoir Content (MAF)	Storage Release (MAF)	Peaking Capacity (Mw)	Max Aval Energy (Kwh × 10^6)	Unused Flow (MAF)	Reduction Factor	Available Head (Ft)
Oct. 1	4.560	0.169	687.2	138.14	0.000	0.640	356.8	7.300	−0.000	2,422.6	502.25	0.120	1.000	429.5
Oct. 11	4.391	0.150	698.4	142.50	0.000	0.660	353.8	7.300	−0.000	1,888.2	364.44	0.000	0.779	431.4
Oct. 21	4.241	0.182	686.9	142.34	0.000	0.659	351.1	7.300	0.073	1,515.7	292.47	0.000	0.626	432.2
Nov. 1	4.058	0.196	680.7	142.14	0.000	0.663	347.7	7.227	0.146	1,377.5	265.87	0.000	0.569	431.4
Nov. 11	3.862	0.196	613.2	128.45	0.000	0.605	344.5	7.081	0.219	1,465.8	283.18	0.000	0.605	428.7
Nov. 21	3.666	0.192	553.8	115.99	0.000	0.553	341.3	6.862	0.219	1,390.7	269.16	0.000	0.574	425.3
Dec. 1	3.475	0.210	572.4	119.35	0.000	0.580	337.7	6.643	0.241	1,359.8	263.83	0.000	0.561	421.8
Dec. 11	3.265	0.210	537.9	110.96	0.000	0.554	333.5	6.402	0.241	1,265.4	246.59	0.000	0.522	417.4
Dec. 21	3.055	0.210	516.2	104.98	0.000	0.541	328.8	6.161	0.248	1,180.9	232.17	0.000	0.487	411.0
Jan. 1	2.845	0.210	488.4	99.04	0.000	0.523	324.0	5.913	0.336	1,285.1	254.46	0.000	0.535	403.4
Jan. 11	2.636	0.210	475.3	96.15	0.000	0.520	319.0	5.577	0.343	1,249.0	246.89	0.000	0.531	396.1
Jan. 21	2.426	0.210	464.8	93.86	0.000	0.522	313.8	5.234	0.343	1,179.6	232.91	0.000	0.514	388.5
Feb. 1	2.216	0.237	502.2	101.31	0.000	0.581	307.7	4.891	0.511	1,436.2	282.95	0.000	0.650	379.3
Feb. 11	1.979	0.237	472.6	95.35	0.000	0.567	300.9	4.380	0.511	1,380.5	270.83	0.000	0.671	365.4
Feb. 21	1.742	0.233	452.9	91.46	0.000	0.566	293.6	3.869	0.511	1,324.2	259.07	0.000	0.697	348.3

Mar. 1	1.509	0.237	536.3	107.92	0.000	0.702	285.2	3.358	0.489	1,254.2	244.91	0.000	0.705	334.7
Mar. 11	1.272	0.237	655.4	131.28	0.000	0.908	275.4	2.869	0.489	1,242.7	241.07	0.000	0.764	317.9
Mar. 21	1.035	0.233	678.3	143.64	0.001	1.000	265.4	2.380	0.482	1,221.4	234.95	0.000	0.817	303.3
Apr. 1	0.803	0.123	629.1	150.98	0.022	1.000	254.1	1.898	0.423	1,184.7	226.38	0.000	0.868	288.2
Apr. 11	0.679	0.123	599.8	143.96	0.092	1.000	247.3	1.475	0.409	1,150.0	218.60	0.000	0.942	270.7
Apr. 21	0.556	0.169	574.7	137.92	0.032	1.000	241.5	1.066	0.482	1,084.6	210.15	0.059	1.000	253.9
May 1	0.388	−0.274	504.1	98.62	0.000	0.945	231.9	0.584	0.255	898.6	169.47	0.000	0.952	236.9
May 11	0.661	−0.274	584.5	115.34	0.000	0.966	248.5	0.328	0.328	858.6	173.31	0.139	1.000	226.6
May 21	0.935	−0.274	642.0	127.65	0.000	0.970	261.7	−0.000	−0.000	750.5	156.92	0.099	1.000	213.5
June 1	1.208	−0.365	672.7	134.58	0.000	0.947	272.8	−0.000	−0.000	729.6	175.11	0.626	1.000	210.9
June 11	1.573	−0.502	691.0	139.11	0.000	0.899	286.1	−0.000	−1.533	728.3	174.80	0.672	1.000	210.8
June 21	2.075	−0.365	715.0	144.24	0.000	0.853	302.0	1.533	−1.752	1,204.6	289.10	0.952	1.000	268.6
July 1	2.440	−0.456	714.6	144.26	0.000	0.808	312.3	3.285	−1.460	1,705.5	409.32	0.982	1.000	326.7
July 11	2.896	−0.456	785.3	159.16	0.000	0.844	323.2	4.745	−1.460	2,092.0	502.07	1.435	1.000	368.5
July 21	3.352	−0.319	767.3	158.45	0.000	0.789	333.8	6.205	−1.095	2,405.9	577.43	1,569	1.000	403.9
Aug. 1	3.671	−0.365	900.4	188.17	0.000	0.007	339.1	7.300	−0.000	2,422.6	581.41	3.237	1.000	422.5
Aug. 11	4.036	−0.456	1,012.4	211.16	0.095	1.000	344.1	7.300	−0.000	2,422.6	581.41	4.399	1.000	422.6
Aug. 21	4.492	−0.068	1,032.8	247.88	0.288	1.000	349.1	7.300	−0.000	2,422.6	581.41	4.198	1.000	422.5
Sept. 1	4.560	−0.000	1,054.5	219.01	0.113	1.000	353.2	7.300	−0.000	2,422.6	581.41	3.237	1.000	422.5
Sept. 11	4.560	−0.000	908.7	183.90	0.000	0.852	355.4	7.300	−0.000	2,422.6	581.41	1.604	1.000	424.5
Sept. 21	4.560	0.068	855.6	172.87	0.000	0.801	355.7	7.300	−0.000	2,422.6	581.41	0.129	1.000	428.5

Mangla Drawdown: 1,075 feet. Tarbela Release Pattern: October 8, 1965.

APPENDIX TABLE 6-5

MANUAL SIMULATION OF TARBELA RESERVOIR OPERATION—12 UNITS

Mean Year Flows—Drawdown Level 1,332

Gross Storage = 11.10 MAF—Live Storage = 8.60 MAF

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
								Output of 1 Unit			Output of 12 Units			
		Storage Release												
Date	Inflow (MAF)	(%)	(MAF)	Outflow (MAF)	Reservoir Content (MAF)	Reservoir Elevation (Ft)	Net Head (Ft)	Capacity (mw)	Dis-charge (MAF)	Energy (M. kwh)	Capacity (mw)	Dis-charge (MAF)	Energy (M. kwh)	O.F. (%)
Oct. 1	1.087	0	0	1.087	11.100	1,550	430	210	.137	50.4	2,520	1.644	400	66.1
Oct. 11	.840	0	0	.840	11.100	1,550	430	210	.137	50.4	2,520	1.644	309	51.1
Oct. 21	.653	0	0	.653	11.100	1,550	430	210	.137	50.4	2,520	1.644	240	39.7
Nov. 1	.572	2.7	.232	.804	11.100	1,550	430	210	.137	50.4	2,520	1.644	295	48.8
Nov. 11	.506	2.7	.232	.738	10.868	1,546	426	210	.139	50.4	2,520	1.668	268	44.3
Nov. 21	.456	2.6	.224	.680	10.636	1,541	421	210	.140	50.4	2,520	1.680	245	40.5
Dec. 1	.418	3.7	.318	.736	10.412	1,538	418	210	.141	50.4	2,520	1.692	263	43.5
Dec. 11	.400	3.7	.318	.718	10.094	1,532	412	209	.143	50.2	2,508	1.716	252	41.8
Dec. 21	.380	3.6	.310	.690	9.776	1,527	407	207	.143	49.7	2,484	1.716	240	40.2
Jan. 1	.355	7.0	.602	.957	9.466	1,521	401	203	.142	48.7	2,436	1.704	329	56.2
Jan. 11	.350	7.0	.602	.952	8.864	1,512	392	196	.138	47.1	2,352	1.656	325	57.4
Jan. 21	.342	7.0	.602	.944	8.262	1,500	380	185	.135	44.4	2,220	1.620	310	58.2
Feb. 1	.347	8.7	.748	1.095	7.660	1,484	364	175	.130	42.0	2,100	1.560	354	70.3
Feb. 11	.358	8.7	.748	1.106	6.912	1,469	349	164	.126	39.3	1,968	1.512	345	73.0
Feb. 21	.372	8.6	.740	1.112	6.164	1,450	330	148	.119	35.5	1,776	1,428	332	78.0

Mar. 1	.394	6.3	.542	.936	5.424	1,431	311	134	.118	32.2	1,608	1.416	256	66.2
	.416	6.3	.542	.958	4.882	1.415	295	123	.108	29.5	1,476	1.296	262	74.0
	.492	6.4	.550	1.042	4.340	1,398	278	108	.103	25.9	1,296	1.236	262	84.4
Apr. 1	.584	3.3	.284	.868	3.790	1,378	258	94	.098	22.8	1,128	1.176	203	74.0
	.645	3.3	.284	.929	3.506	1,368	248	87	.095	20.9	1,044	1.140	204	81.4
	.810	3.4	.292	1.102	3.222	1,357	237	78	.092	18.7	936	1.104	224	100.0
May 1	1.022	1.7	.146	1.168	2.930	1,348	228	73	.089	17.5	876	1.068	210	
	1.348	1.7	.146	1.494	2.784	1,344	224	69	.088	16.6	828	1.056	199	
	1.913	1.6	.138	2.051	2.638	1,336	216	64	.084	15.3	768	1.008	184	
June 1	2.955	−15.0	−1.290	1.665	2.500	1,332	212	61	.083	14.6	732	.996	175	
	3.765	−15.0	−1.290	2.475	3.790	1,377	257	93	.098	22.3	1,116	1.176	268	
	4.120	−15.0	−1.290	2.830	5.080	1,420	300	126	.111	30.2	1,512	1.332	362	
July 1	5.170	−18.0	−1.550	3.620	6.370	1,455	335	154	.122	37.0	1,848	1.466	444	
	5.420	−18.0	−1.550	3.870	7.920	1,492	372	180	.133	43.2	2,160	1.596	519	
	5.640	−19.0	−1.630	4.010	9.470	1,521	401	203	.141	48.7	2,436	1.696	585	
Aug. 1	5.910	0	0	5.910	11.100	1,550	430	210	.137	50.4	2,520	1.644	605	
	5.210	0	0	5.210	11.100	1,550	430	210	.137	50.4	2,520	1.644	605	
	4.160	0	0	4.160	11.100	1,550	430	210	.137	50.4	2,520	1.644	605	
Sept. 1	3.095	0	0	3.095	11.100	1,550	430	210	.137	50.4	2,520	1.644	605	
	2.235	0	0	2.235	11.100	1,550	430	210	.137	50.4	2,520	1.644	605	
	1.545	0	0	1.545	11.100	1,550	430	210	.137	50.4	2,520	1.644	569	94.0
									Total:	1,407.5		Total:	12,458	

NOTE: Column 7, the reservoir elevation, is read on Appendix Figure 6-1 against Reservoir storage; Column 8 indicates the net head on the turbines and is derived from the figure shown in Column 7 a constant value of 1120 feet, representing the tailwater elevation with an allowance for hydraulic losses. Columns 9 and 10 are respectively the capacity and discharge of one unit operating with the head given in Column 8. The product of the capacity (Column 9) and 240 (the number of hours in a 10-day period) is the energy generated by one unit during a 10-day period, assuming no lack of outflows, and it is shown in Column 11. Columns 12 and 13 give the capacity and discharge corresponding to 12 units and they are calculated by multiplying the figures in Columns 9 and 10 by 12 (units). The ratio between the amount of water available for discharge (outflow, Column 5) and the maximum amount of water which could be discharged by 12 turbines (Column 13) is given in Column 15 as o.f. (operation factor). The energy generated by 12 units, which is the product of the energy output of one unit (Column 11), times 12 units, and the operation factor (Column 15), is shown in Column 14.

APPENDIX TABLE 6-6
MANUAL SIMULATION OF TARBELA—12 UNITS[a] AT MEAN YEAR FLOWS
FULL STORAGE LEVEL: 1550

	Drawdown Level 1,300		Drawdown Level 1,332	
	Capability (mw)	Energy (mln. kwh)	Capability (mw)	Energy (mln. kwh)
Jan.	2,208	1,027	2,220	964
Feb.	1,660	994	1,764	977
Mar.	1,124	737	1,296	746
Apr.	752	531	972	621
May	520	372	786	570
June	1,342	972	1,704	1,224
July	2,340	1,685	2,520	1,818
Aug.	2,520	1,815	2,520	1,818
Sept.	2,520	1,815	2,520	1,818
Oct.	2,520	1,008	2,520	1,012
Nov.	2,520	834	2,520	814
Dec.	2,450	795	2,460	772
		12,585		13,154
Minimum Capability:	456 mw (June 1)		732 mw (June 1)	
Total Energy:	12,585 mln. kwh.		13,154 mln. kwh.	

[a] Data derived for use in the power system simulation studies for purposes of system dispatch. It will be noted that the energy figures diverge slightly from those given in Appendix Table 6-5; again the reason is that the two analyses were based on slightly different assumptions regarding the distribution of mean-year flows among 10-day periods.

SUPPLEMENTAL PAPER VII

Power Aspects of the Tarbela Project

The Tarbela Project, as evaluated in this Report, will be the largest water storage and hydroelectric project in Pakistan; in fact, it probably represents the largest single construction contract ever to have been let in the world. As discussed in Annex I to Volume I, the site was selected by WAPDA in 1961 as a result of detailed studies which began in 1954 of three potential locations in a 15-mile stretch of the Indus River. As this is written, Tippetts-Abbett-McCarthy-Stratton International Corporation (TAMS) of New York City, consulting engineers to WAPDA, were completing the final designs and contract documents for the project. The project, as envisaged, comprises essentially a major earth and rockfill dam rising 485 feet above riverbed level with a crest length of about 9,000 feet and an impervious blanket extending some 5,000 feet upstream, two auxiliary embankment dams, two chute spillways, and four outlet tunnels each of 45 feet maximum diameter.

The powerhouse would be located on the right bank of the river at the foot of the dam. The substructure is designed to be constructed in stages of four generating units each and each group of four units will be served by one penstock tunnel. It was recently decided to build the powerhouse initially to house four generating units. Eight more units would be installed at a later date as they are needed. On present designs the third tunnel will be adaptable for power use when required. The fourth tunnel is being designed strictly for irrigation, but it would be possible to make it adaptable for power purposes as well, thus enabling an additional four units to be installed, making 16 units in all. Each unit, rated at 175 mw, would have a capability range of 183 mw (or 210 mw with 15 percent overload) under full head and low tailwater conditions to about 40 mw at the 1300 foot drawdown level.

Seasonal Fluctuations

It was pointed out in Supplemental Paper No. 6 that the extreme seasonal fluctuations in flows on the Indus and the variation in storage releases required for irrigation purposes in the different months of the year provide a poor seasonal distribution of water for power production. The range of variation in the capability of the units at Tarbela is indicated in Table 7-1. The exact significance of these minimum capabilities will depend on the monthly pattern of peak loads and the seasonal variation in the capability of other hydro units on the system at the same time. It will be seen below that, even though Tarbela will reach minimum capabil-

TABLE 7-1
TARBELA—GROSS CAPACITY OF 1 UNIT IN DIFFERENT MONTHS

	Drawdown Level: 1,332 feet		Drawdown Level: 1,300 feet	
	mw	million kwh	mw	million kwh
Minimum				
May 11–21	69	50	50	37
May 21–31	64	47	42	31
June 1–10	61	45	38	28
Maximum				
August	210	153	210	153
September	210	153	210	153

ity in early June, the critical period on the system as a whole is likely to be in May when Tarbela is fully developed, this is because Mangla, having begun to fill earlier, will be well above minimum capability by the beginning of June.

UNITS 13-16 AT TARBELA

Though it would be possible to install 16 units at Tarbela as pointed out earlier, the analyses presented in this Supplemental Paper were conducted in terms of a maximum of 12 units. The main attraction of units 13-16 is that they would add capability which would generally be able to produce base-load energy in the critical period of the year from the end of April to the beginning of June. Thus, depending on the minimum reservoir level maintained, they would add to the system's firm capability in the 1980's about 200 mw (in early May, with drawdown level of 1300 feet) or about 260 mw (in early May, with drawdown level of 1332 feet). With a minimum drawdown level of 1332 feet, they would add about 200 million kwh of energy during the critical May-June period under mean-year conditions. They would also add about another 1,800 million kwh to the output of the Tarbela power plant in June-September, but our studies suggest that the other hydro units envisaged (i.e. existing plants plus Mangla 1-8 and Tarbela 1-12) would already be producing more energy in most of these months than could be absorbed by the system until the late 1980's. However, it is also about that time—the late 1980's—that the release capacity of the tunnels as presently designed (i.e., three for power and one for irrigation) may, according to the irrigation consultant's projections of kharif irrigation requirements, become inadequate to permit required releases during the period when the reservoir is fully drawn down. Conversion of the fourth tunnel to power would cut the maximum outlet capability of one irrigation tunnel plus three power tunnels (including their bypass valves) from about 118,000 cfs to about 65,000 cfs at reservoir elevation 1332 feet. Irrigation requirements for releases in June have been projected at 156,000 cfs by 2000. Straight conversion of Tunnel 4 to power would thus be unacceptable from the irrigation point of view. Other solutions, such as addition of a fifth tunnel, would be extremely expensive.[1] The power consultant, making allowance only for the lining of the downstream end

[1] Discussed in the consultants' report: Chas. T. Main, Program for Development of Surface Storage in the Indus Basin and Elsewhere within West Pakistan: Comprehensive Reports Volume II (August, 1966), pp. II-1-22 through II-1-27.

of Tunnel 4 and its adaptation for power use, estimated that Units 13-16 would be about 40 percent more expensive than other Tarbela units. This would put them at about $350 per kw available at the time of system minimum capability. He pointed out that additional transmission would be required to carry the power generated in the flood season. Addition of these costs and of the costs of adjustment to meet irrigation requirements, even on the assumption that some relatively inexpensive solution to this problem might yet be found, would seem to make Tarbela Units 13-16 unattractive compared with alternatives available to Pakistan for the 20 to 30 years with which we are here concerned. The situation could be very different 40 years after Tarbela is completed; by then the higher drawdown level will increase the minimum discharge through the power tunnels and additional storage will be available elsewhere to meet the main irrigation requirements.

Power Benefits of Tarbela

It was pointed out in Volume One (Chapter 6) that a dual approach was taken to the evaluation of Tarbela's power benefits. In both approaches, net benefits were identified as the difference between the cost of a power program including Tarbela and one excluding Tarbela. The first approach compared Tarbela with the cheapest alternative power program and showed the sensitivity of the benefits to different assumptions regarding the foreign exchange rate and fuel prices. The alternative power program for this purpose was built on the assumption that if Tarbela was not built by 1975/76 it would never be built. However, the capital cost savings obtainable from postponing such a major investment as the Tarbela Project by even a few years are considerable, and therefore a second analysis was undertaken comparing a program which included completion of the Tarbela Dam in 1975 with another program which included its completion in 1985. Since the first approach showed Tarbela to be an attractive project from the power point of view at any likely fuel price in West Pakistan, and the second analysis was concerned with its precise timing, all the calculations for the second approach were made in terms of the economic fuel prices shown in Figure 3-1 of Supplemental Paper No. 3, for these fuel prices represent estimates of the scarcity value of thermal fuel in each year of the planning period.

Establishing the Cheapest Alternative to Tarbela

The first task was to establish the best alternative to Tarbela from the power point of view. In their 1964 report on the Tarbela Project, S&W had prepared an alternative program which included the Kunhar Project and extensive thermal development at Mari with a 380-kv transmission line linking Mari and the North. These alternative programs were designed to meet only the power requirements of the Northern Grid zone. However, the basic elements of this program were used to develop an alternative program to Tarbela for meeting the requirements of all the main load centers of West Pakistan.

The first alternative program prepared included a 380-kv interconnection between Mari and Karachi (thus enabling advantage to be taken of the gas reserves at Mari) and the Kunhar Project. This project on the Kunhar River, between 30 and 70 miles upstream of its confluence with the Jhelum River, would be primarily for power, but would add an estimated 0.378 MAF of storage capacity in the Jhelum

Basin. The project would develop power from a drop of more than 4,000 feet over a 35-mile reach of river. The project would consist initially of a concrete, gravity dam, 530 feet high, at Suki Kinari (see Map 2). A 16-foot diameter, concrete-lined tunnel, eight miles long, would carry the water from the Suki Kinari Reservoir under the mountains, across a loop in the river, to steel penstocks terminating in a powerhouse at Paras. The installation in the Paras Power Station would operate under a head of about 3,000 feet and would consist of two generating units each rated at 122 MVA at 0.90 p.f.

The second stage of the project would consist of the construction of a concrete gravity dam, 410 feet high, at Naran on the Kunhar River upstream of the Suki Kinari Reservoir to improve regulation of discharge and permit the addition of two generating units to the Paras Power Plant. In the ultimate stage of development, a 14-foot diameter, concrete-lined tunnel, about seven miles long, would be built to convey water from the Naran Dam to a power plant situated at the upstream end of the Suki Kinari Reservoir and containing three generating units each rated at 44.5 MVA continuous. The estimated cost of the project (prepared by WAPDA's consultants in 1961) is shown in Table 7-2 with other relevant data.

In evaluating this project, it was found that, except at rather high prices for thermal fuel, Kunhar was a relatively unattractive project. Therefore, two other programs were prepared, one including Kunhar commencing in 1981, and the other excluding Kunhar altogether. The last in effect constitutes a purely thermal alternative (except for the existing small hydels and Warsak, and the planned Mangla Units 1-8 and Warsak Units 5 and 6). Since it is now very doubtful whether there exists at Mari such a large reserve of cheap gas as was believed to be the case two years ago, the 380-kv transmission line between Mari and Karachi was also eliminated from the program. Since most of this analysis was conducted in terms of uniform fuel prices, this also served to focus attention entirely on the effects of changes in assumptions regarding the availability and price of fuel.

The resultant development programs are outlined in detail in Table 7-3. On the right-hand side are shown a single program for Mari and a single program for Karachi-Hyderabad. They were combined with each of the three different programs shown on the left for the Northern Grid: Program A including Kunhar coming in in 1974, Program B including Kunhar commencing 1981, and Program C being the so-called all-thermal program. These programs could undoubtedly be refined. The direction of refinement would often depend, however, on making a more precise initial assumption with regard to the price of thermal fuel. For instance, the Mangla units are probably scheduled earlier than would be sensible without interconnection unless the fuel price is assumed to be very high. Other

TABLE 7-2
KUNHAR RIVER PROJECT

		Stage I	Ultimate Development (Stages I, II & III)
Firm Capability (total)	mw	198	500
Annual Energy	million kwh	1,014	2,545
Live Storage Capacity	MAF	0.128	0.378
Estimated Cost[a]	$ million equiv.	110	195

[a] 1961 price levels. The cost of an 80-mile transmission line to Wah is included. The cost estimates have not been updated for the purposes of this report.

refinements would be possible too—adequate allowance is not always made for reserves and some of the units brought in are larger than would be appropriate for markets of the size that will be in existence if interconnection is not undertaken. For the purpose of a rough assessment of the power benefits from Tarbela at different fuel prices, however, the programs seem adequate.

Figure 7-1 compares the discounted present worth of the cost of these programs at different prices for natural gas. Virtually all the thermal generation in these programs is assumed to be gas-fired; the only significant exception to this is a small amount of nuclear capability included in the South in each of the programs for the early 1980's. Natural gas was also assumed, for these analyses, to have a uniform price throughout West Pakistan. Therefore, the figure gives a direct indication of the effect that different assumptions regarding fuel have on the relative attractiveness of various programs alternative to Tarbela.

Side Benefits to Kunhar

There are two side benefits which have to be taken into account in consideration of the Kunhar Project. In the first place, it would provide a small amount of live storage. The project, as designed by Chas. T. Main, would include live storage of about 0.128 MAF behind the Suki-Kinari Dam, which would be completed about 1973/74 in our early Kunhar program and about 0.250 MAF behind the Naran Dam, which would be completed about 1975/76 under the same program. The linear programming analysis of agricultural development suggests that the present worth of the benefit of this storage capacity might be about $10 million. Apart from these irrigation benefits, regulation of the Kunhar River, a tributary of the Jhelum, could also increase the capability of the Mangla units in the critical period from March through May and increase the amount of energy which could be generated at Mangla in those months by storing kharif water and releasing it in the critical months. Insufficient information is available to make a full analysis of the benefits attributable to Kunhar on this account, and the irrigation and power uses of the Kunhar storage could be incompatible depending on the timing of irrigation requirements. However, the added capability and energy generation at Mangla which would result from the construction of Kunhar have been estimated as in Table 7-4. These figures show that the important effects of Kunhar on Mangla are an increase of the capability in the critical month of March by about 70 mw and an increase in the amount of energy available in months when it could normally be used (i.e. excluding July) of nearly 200 million kwh. These are rough order-of-magnitude estimates but they serve for the present purpose. They imply that early construction of Kunhar could reduce the investment needed in new thermal capacity in 1978 by about 75 mw and increase the amount of useful hydro energy available after that date by about 200 million kwh a year. These savings have a present worth of about $6 million, if the fuel savings are valued at the low (20 cents) price for fuel and about $11 million if the fuel savings are valued at the high (70 cents) price for fuel. If Kunhar were to be postponed to 1981, as in Program B, then the irrigation benefits and power savings would have a combined present-worth value of about $8 million at the lower fuel price and $10 million at the higher fuel price. The results of these calculations are also indicated in Figure 7-1, by the dotted lines beneath the continuous lines which represent the direct costs of the various programs on the power side.

TABLE 7-3

ALTERNATIVE PROGRAMS WITHOUT TARBELA

	North, Program A		North, Program B		North, Program C			Mari			Karachi-Hyderabad		
	System Additions	Capability (mw)	System Additions	Capability (mw)	System Additions	Capability (mw)	North Peak Load (mw)	System Additions	Capability (mw)	Peak Load (mw)	System Additions	Capability (mw)	Peak Load (mw)
1966	Existing	467	Existing	467	Existing	467	513(Oct)	Existing	50	11(Oct)	Existing	280	194(Dec)
1967	Lyallpur S1(124)	457	Lyallpur S1(124)	457	Lyallpur S1(124)	457	513(Jan)		50	17(Oct)	Hyderabad S2(15)	307	225(Oct)
	Mangla 1 & 2 (90)		Mangla 1 & 2 (90)		Mangla 1 & 2 (90)						Kotri OFT (12)		
1968	Lahore GT2 (26)	743	Lahore GT2 (26)	743	Lahore GT2 (26)	743	598(Mar)		50	22(Oct)	Kotri GT (40)	347	271(Oct)
	Lahore GT3 (26)		Lahore GT3 (26)		Lahore GT3 (26)								
1969	Mangla 3 (45)	788	Mangla 3 (45)	788	Mangla 3 (45)	788	690(Mar)		50	29(Oct)	Korangi 3 (125)	472	321(Oct)
1970	Mangla 4 (45)	923	Mangla 4 (45)	923	Mangla 4 (45)	923	813(Mar)	Mari 1 (100)	150	45(Oct)	Hyderabad GT2 (26)	498	382(Oct)
	Mangla 5 & 6 (90)		Mangla 5 & 6 (90)		Mangla 5 & 6 (90)								
1971	Lyallpur P (100)	1,008	Lyallpur P (100)	1,008	Lyallpur P (100)	1,008	909(Mar)		150	54(Oct)	Karachi N1 (25)	648	442(Oct)
	Retire: LYA S (10)		Retire: LYA 5 (10)		Retire: LYA S (10)						Korangi 4 (125)		
	MONT S (5)		MONT S (5)		MONT S (5)								
1972	Mangla 7 & 8 (90)	1,098	Mangla 7 & 8 (90)	1,098	Mangla 7 & 8 (90)	1,098	1,004(Mar)		150	65(Oct)	Karachi N1 (100)	748	514(Oct)
1973	Lyallpur 1 (100)	1,198	Lyallpur 1 (100)	1,198	Lyallpur 1 (100)	1,198	1,099(Mar)		150	76(Oct)	Retire: KAR A (15)	733	600(Oct)
1974	Kunhar 1 (216)	1,404	Lyallpur 2 (100)	1,298	Lyallpur 2 (100)	1,298	1,196(Mar)		150	89(Oct)	Karachi 1 (100)	833	692(Oct)
1975	Warsak 5 & 6 (80)	1,484	Lyallpur 5 (150)	1,528	Lyallpur 5 (150)	1,528	1,306(Mar)		150	105(Oct)	Karachi 2 (150)	983	795(Oct)
1976	Kunhar 2 (108)	1,592	Warsak 5 & 6 (80)	1,528	Warsak 5 & 6 (80)	1,528	1,394(Mar)	Mari 1a(100)	250	115(Oct)		983	889(Oct)
1977	Kunhar 3 (108)	1,700	Lyallpur 5a (150)	1,678	Lyallpur 5a (150)	1,678	1,493(Mar)		250	126(Oct)	Korangi 5 (200)	1,183	998(Oct)
1978	Kunhar 4 (92)	1,792	Lyallpur 5b (150)	1,828	Lyallpur 5b (150)	1,828	1,601(Mar)		250	137(Oct)		1,183	1,101(Oct)
1979	Lyallpur 5 (150)	1,942	Lyallpur 5c (150)	1,978	Lyallpur 5c (150)	1,978	1,708(Mar)		250	148(Oct)	Karachi 3 (250)	1,433	1,234(Oct)
1980		1,942		1,978		1,978	1,837(Mar)		250	162(Oct)	Korangi 7 (300)	1,733	1,370(Oct)
1981	Lyallpur 6 (200)	2,142	Kunhar 1 (216)	2,194	Lyallpur 6 (200)	2,178	1,959(Mar)		250	178(Oct)		1,733	1,499(Oct)
1982	Lyallpur 7 (200)	2,342	Lyallpur 7 (200)	2,394	Lyallpur 7 (200)	2,378	2,087(Mar)	Mari 1b (100)	350	193(Oct)	Korangi 7a (300)	2,033	1,642(Oct)
1983	Lyallpur N1 (300)	2,642	Kunhar 2 (108)	2,502	Lyallpur N1 (300)	2,678	2,225(Mar)		350	210(Oct)		2,033	1,776(Oct)
1984		2,642	Kunhar 3 (108)	2,610		2,678	2,356(Mar)		350	229(Oct)	Korangi N4 (400)	2,433	1,971(Aug)
1985	Lyallpur 2 (100)	2,742	Kunhar 4 (92)	2,702	Lyallpur 2a (100)	2,778	2,505(Mar)		350	250(Oct)		2,433	2,154(Aug)

TABLE 7-4
EFFECT OF KUNHAR ON POWER OUTPUT FROM MANGLA[a]
(Mangla 8 Units—Drawdown Level 1,040 feet)

	Critical Year Capability (mw)		Mean-Year Energy (million kwh)	
	Without Kunhar	With Kunhar	Without Kunhar	With Kunhar
January	546	546	338	348
February	688	728	405	419
March	520	592	387	440
April	384	488	276	351
May	520	584	386	434
June	768	752	551	540
July	928	888	690	660

[a] These figures, taken from Stone & Webster's "Draft Report on Water and Power Resources of West Pakistan—1964 Tarbela Study" (December, 1964) are not directly comparable with other figures used in this paper. Months not mentioned in the table are not affected by the installation of the Kunhar dams.

APPRAISAL OF KUNHAR AS ALTERNATIVE

The evidence presented in Figure 7-1 suggests that Kunhar is not a very attractive project, and that only by the addition of the side benefits which might accrue from its effect on irrigation supplies and on the capability at Mangla does it become marginally interesting. Even with foreign exchange valued at the current official rate, programs which include Kunhar are less attractive than the 'all-thermal' alternative at any fuel price below about 40 cents per million Btu. Without taking account of these special benefits of Kunhar the breakeven point arrives only at a fuel price of over 50 cents per million Btu. At the higher foreign exchange rate the programs including Kunhar are considerably less attractive; the program with Kunhar in 1974 is not at all competitive and that with Kunhar in 1981 breaks even with the 'all-thermal' alternative only at a fuel price of over 50 cents per million Btu.

There is another factor which raises doubts about Kunhar. The cost estimates for the project, except for the special addition made here to cover transmission, are all based on 1961 U.S. and Pakistani prices. Other prices used in this report are as of mid-1965. The magnitude of the adjustment that would be necessary to bring the Kunhar costs up-to-date is uncertain but this does suggest that the breakeven points between Kunhar and a purely thermal alternative given here are minimal; Kunhar may well be attractive only if fuel prices are substantially higher.

The figures as they stand, however, would suggest that Kunhar is preferable to a thermal program only if foreign exchange is valued at the current rate. WAPDA now pays a price of somewhat below 50 cents per million Btu for the bulk of its thermal fuel, so that the 40 cents breakeven point for the Kunhar programs would imply that Kunhar is a sound project. When foreign exchange is valued at a rate closer to its true scarcity value the breakeven point between the two programs exceeds this fuel price. The result is confirmed by the figures in Table 7-5. The figures in this table represent the discounted present worth of the costs of three programs similar to those discussed above in every way, except that they each in-

TABLE 7-5
PRESENT-WORTH COSTS OF ALTERNATIVE PROGRAMS EXCLUDING TARBELA WITH FUEL VALUED AT CURRENT PRICES TO UTILITIES
($ million)

	Foreign Exchange Rate	
	Current	Shadow
	($1 = Rs. 4.76)	($1 = Rs. 9.52)
Program A (Kunhar 1974)[a]	687	1,007
Program B (Kunhar 1981)[a]	695	987
Program C (All-Thermal)	697	984

[a] Total cost figures presented here net of present-worth value of special side benefits of Kunhar discussed above.

clude development of about 1,000 mw at Mari/Sui and construction of a 380-kv transmission system between Mari and Karachi. The fuel requirements of these programs have been priced at the rate currently paid—i.e., about 50 cents per million Btu for WAPDA-North, 44 cents for WAPDA-Sind and 36 cents for KESC—together with an arbitrarily selected 'financial' price of 14 cents per million Btu at Mari/Sui. This table shows how the 'all-thermal' program is the worst when foreign exchange is valued at the current rate and the best when foreign exchange is valued at its scarcity price.

PROGRAMS INCLUDING TARBELA

Despite the uncertainty of the special side benefits which may accrue from construction of Kunhar, they were taken into account in the choice of programs constituting the cheapest alternative to Tarbela under various economic conditions. This helps to ensure that any error is in the direction of underestimating the power benefits of Tarbela rather than exaggerating them. These cheapest alternative power programs are compared in Figure 7-2 with two programs which include Tarbela in 1975. The two programs including Tarbela are outlined in Tables 7-6 and 7-7. The first (Table 7-6) omits interconnection and therefore phases the introduction of hydro units at Tarbela in accordance with the capacity of the Northern Grid to absorb additional hydro energy. The second program (Table 7-7) includes interconnection and brings in the Tarbela units more rapidly. Figure 7-2 compares the cost of these three programs at different shadow prices for fuel and for foreign exchange (i.e. excluding the cost of the Tarbela dams). As in the comparisons shown in Figure 7.1, thermal fuel is here assumed to have a single price wherever it may be used in the Province.

PROGRAMS INCLUDING TARBELA VS. CHEAPEST ALTERNATIVES

It is clear from Figure 7-2 that power programs which include Tarbela are substantially cheaper than the cheapest alternative, in terms of discounted present worth, at all fuel prices above 20 cents per million Btu. Even at 20 cents per million Btu, fuel savings involved in a with-Tarbela program are about $40 million when foreign exchange is valued at the current rate, but they are almost insignificant when foreign exchange is valued at the higher rate used here. The costs of the programs cited here do not include the costs of gas transmission lines, so that it is hard to apply here directly the estimates of the scarcity value of thermal fuel developed in Supplemental Paper No. 3. Nevertheless, those estimates suggested that a reasonable middle range for comparing programs with and without the Tarbela contribution to overall energy supply might be at least 40-50 cents per million Btu. If the costs of the programs discussed here were revalued in terms of

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FIGURE 7.1

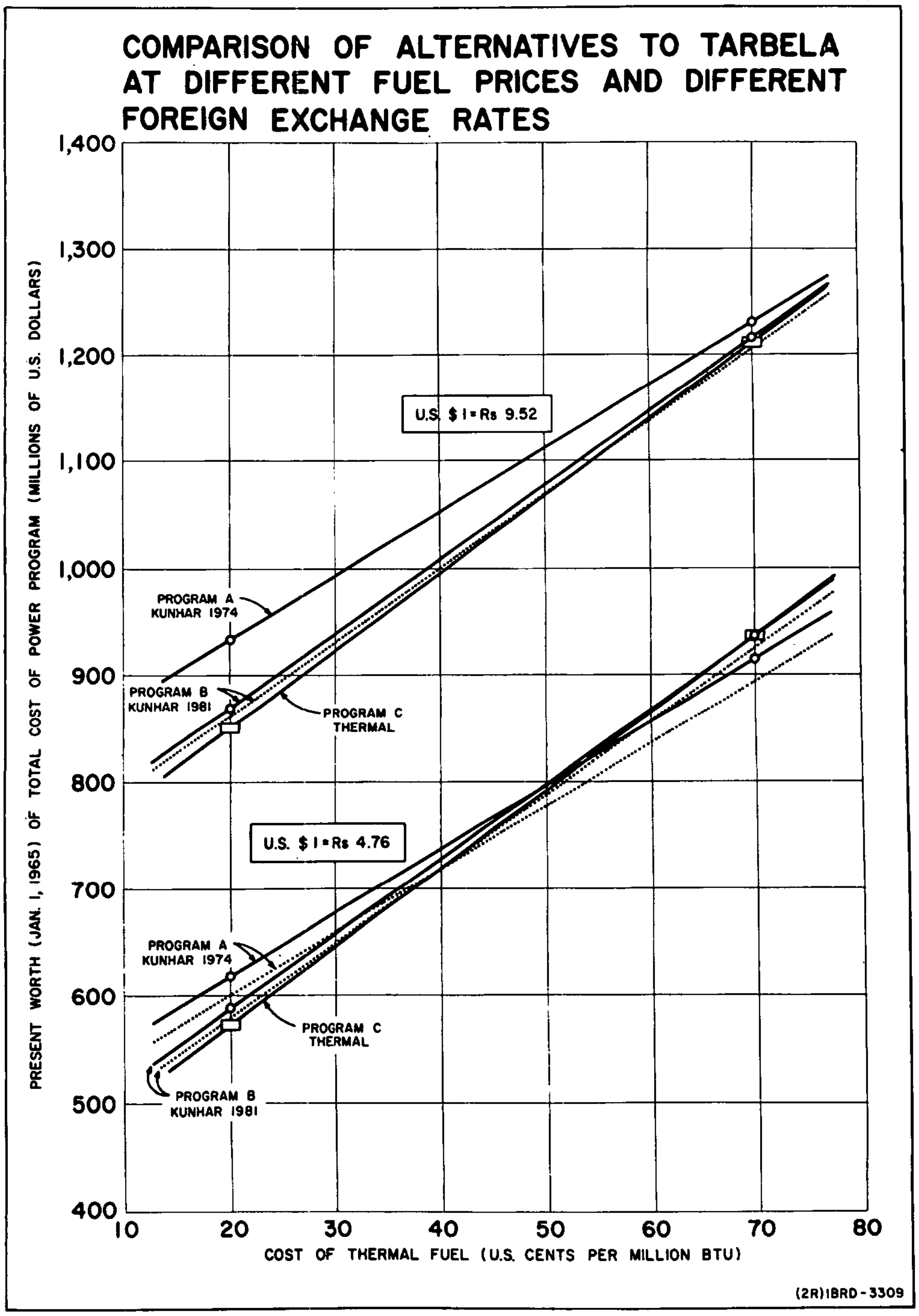

TABLE 7–6

TARBELA WITHOUT INTERCONNECTION

(Tarbela Drawdown Level: 1332 feet)

	Northern Grid					Mari			Karachi—Hyderabad		
	System Additions	Thermal Capability (mw)	Hydro. Capability (mw)	Total Capability (mw)	Peak Load (mw)	System Additions	Capa-bility (mw)	Peak Load (mw)	System Additions	Capability (mw)	Peak Load (mw)
1966	Existing	302	165	467	513 (Oct)	Existing	50	11 (Oct)	Existing	280	194 (Dec)
1967	Lyallpur S1 (124) Mangla 1 & 2 (90)	302	155	457	513 (Jan)		50	17 (Oct)	Hyderabad S2 (15) Kotri OFT (12)	307	225 (Oct)
1968	Lahore GT 2 (26) Lahore GT 3 (26)	478	265	743	598 (Mar)		50	22 (Oct)	Kotri GT (40)	347	271 (Oct)
1969	Mangla 3 (45)	478	310	788	690 (Mar)		50	29 (Oct)	Korangi 3 (125)	472	321 (Oct)
1970	Mangla 4 (45) Lyallpur P1 (100)	578	355	933	813 (Mar)	Mari 1 (100)	150	45 (Oct)	Hyderabad GT 2 (26)	498	382 (Oct)
1971	Lyallpur P2 (100) Retire: LYA S (10) MONT S (5)	663	355	1,018	909 (Mar)		150	54 (Oct)	Karachi N1 (25) Korangi 4 (125)	648	442 (Oct)
1972	Lyallpur P3 (100)	763	355	1,118	1,004 (Mar)		150	65 (Oct)	Karachi N1 (100)	748	514 (Oct)
1973	Mangla 5 & 6 (90)	763	445	1,208	1,099 (Mar)		150	76 (Oct)	Retire: KAR A (15)	733	600 (Oct)
1974	Lyallpur P3 (100)	863	445	1,308	1,196 (Mar)		150	89 (Oct)	Korangi 5 (200)	933	692 (Oct)
1975	Tarbela 1 & 2 (180)	863	625	1,488	1,306 (Mar)		150	105 (Oct)		933	795 (Oct)
1976	Tarbela 3 & 4 (180)	863	805	1,668	1,394 (Mar)	Mari 6 (200)	350	115 (Oct)	Korangi 6 (200)	1,133	889 (Oct)
1977		863	805	1,668	1,493 (Mar)		350	126 (Oct)		1,133	998 (Oct)
1978	Mangla 7 & 8 (90)	863	895	1,758	1,601 (Mar)		350	137 (Oct)	Korangi 7 (300)	1,433	1,101 (Oct)
1979	Critical changes to May Warsak 5 & 6 (80)	863	977	1,840	1,671 (May)		350	148 (Oct)		1,433	1.234 (Oct)
1980	Lyallpur 5 (150)	1,013	977	1,990	1,813 (May)		350	162 (Oct)	Korangi 6a (200)	1,633	1,370 (Oct)
1981	Tarbela 5 & 6 (146)	1,013	1,123	2,136	1,951 (May)		350	178 (Oct)	KAR N 3 (400)	2,033	1.499 (Oct)
1982	Tarbela 7 & 8 (146)	1,013	1,269	2,282	2,095 (May)		350	193 (Oct)		2,033	1,642 (Oct)
1983	Lyallpur 6 (200)	1,213	1,269	2,482	2,248 (May)		350	210 (Oct)	KAR N 4 (400)	2,433	1,799 (Sept)
1984	Tarbela 9 & 10 (146)	1,213	1,415	2,628	2,398 (May)		350	229 (Oct)		2,433	1,971 (Aug)
1985	Tarbela 11 & 12 (146)	1,213	1,561	2,774	2,567 (May)		350	250 (Oct)		2,433	2,154 (Aug)

TABLE 7–7
TARBELA WITH INTERCONNECTION
(Drawdown Levels: Tarbela 1332 feet, Mangla 1040 feet)

	Northern Grid				Peak Loads			Mari		Hyderabad—Karachi		
	System Additions	Thermal Capability (mw)	Hydro. Capability (mw)	Total Capability (mw)	North	Mari	South	System Additions	Capability (mw)	System Additions	Capability (mw)	Cumulative Total System Capability
1966	Existing	302	165	467	513(Oct)	11(Oct)	194(Dec)	Existing	50	Existing	280	
1967	Lyallpur S1 (124) Mangla 1 & 2 (90)	302	155	457	513(Jan)	17(Oct)	225(Oct)		50	Hyderabad S2 (15) Kotri OFT (12)	307	
1968	Lahore GT 2 (26) Lahore GT 3 (26)	478	265	743	598(Mar)	22(Oct)	271(Oct)		50	Kotri GT (40)	347	
1969	Mangla 3 (45)	478	310	788	690(Mar)	29(Oct)	321(Oct)		50	Korangi 3 (125)	472	
1970	Mangla 4 (45) Mangla 5 & 6 (90)	478	445	923	813(Mar)	45(Oct)	382(Oct)	Mari S1 (100)	150	Hyderabad GT 2 (26)	498	
1971	Interconnect w. Mari (380 Kv) Retire: LYA S (10) MONT S (5)	463	445	908		1,334(Mar)		Interconnect with N & S. Mari S 2 (100)	250	Interconnect w.Mari (380 kv) Karachi N 1 (25)	523	1,681
1972		463	445	908		1,501(Mar)			250	Karachi N1 (100)	623	1,781
1973	Mangla 7 & 8 (90)	463	535	998		1,688(Mar)			250	Retire: KAR A (15)	608	1,856
1974		463	535	998		1,877(Mar)		Mari P (200)	450		608	2,056
1975	Tarbela 1 & 2 (180)	463	715	1,178		2,093(Mar)			450	Korangi 4 (125)	733	2,361
1976	Tarbela 3 & 4 (180)	463	895	1,358		2,268(Mar)		Second interconnex. with S.	450	Second interconnexion with Mari	733	2,541
1977		463	895	1,358		2,475(Mar)		Mari S 6 (200)	650		733	2,741
1978	Critical changes to May Tarbela 5 & 6 (146) Warsak (80) 2nd interconnex. with Mari	463	1,123	1,586		2,712(May)		Second interconnex. with N.	650		733	2,969
1979	Tarbela 7 & 8 (146)	463	1,269	1,732		2,966(May)			650	Korangi 5 (200)	933	3,315
1980	Tarbela 9 & 10 (146) Tarbela 11 & 12 (146) 3rd interconn. w. Mari	463	1,561	2,024		2,250(May)		3rd interconn. with N.	650		933	3,607
1981		463	1,561	2,024		3,524(May)			650	Korangi 7 (300)	1,233	3,907
1982	Lyallpur 6 (200)	663	1,561	2,224		3,818(May)		Mari S 7 (200)	850		1,233	4,307
1983		663	1,561	2,224		4,165(May)			850	Karachi N 3 (400)	1,633	4,707
1984		663	1,561	2,224		4,494(May)		Mari S 9 (300)	1,150		1,633	5,007
1985		663	1,561	2,224		4,864(May)			1,150	Karachi N4 (400)	2,033	5,407

the fuel prices calculated in Supplemental Paper No. 3 and the costs of needed gas pipelines were added in, the estimate of savings obtainable on the power side from a with-Tarbela program would probably appear greater because of the very high shadow fuel prices which seemed to be appropriate for the later years—which is the bulk of the period when Tarbela would be providing power to West Pakistan. At a price of 45 cents per million Btu for thermal fuel the saving of a with-Tarbela

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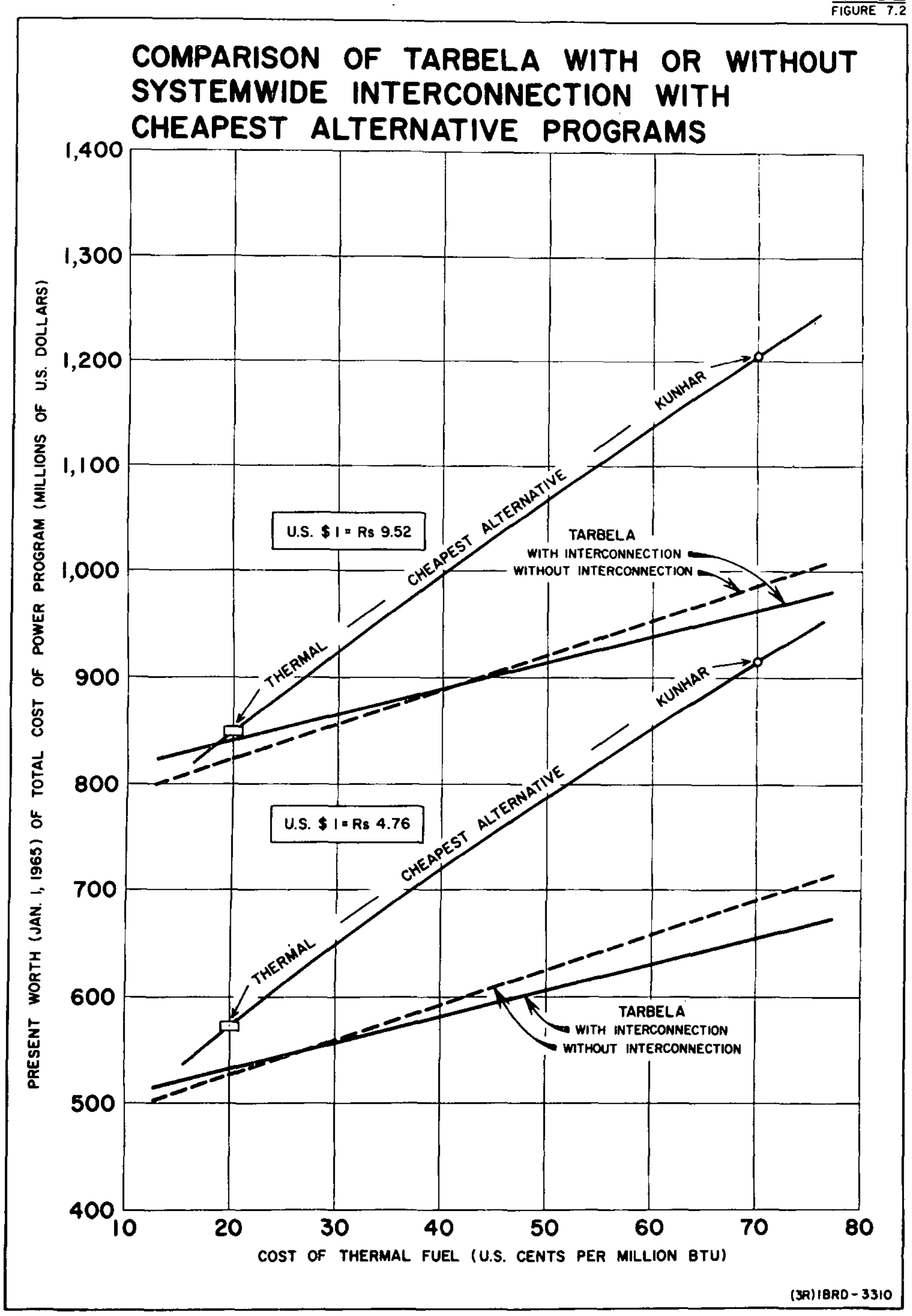
FIGURE 7.2



program over the cheapest alternative is about $180 million at the current foreign exchange rate and $160 million at double the current rate.

Figures were cited above for the costs of without-Tarbela programs when fuel was valued at current financial prices. These programs included about 1,000 mw at Mari/Sui and so they are directly comparable with the with-interconnection Tarbela program here. The figures given in Table 7-8 may be taken as reasonable estimates of the benefits of Tarbela when calculations are made in terms of financial prices. As pointed out, both programs included extensive use of gas at Mari/Sui—which has been valued in both sets of calculations at financial prices of 14 cents per million Btu. Supplemental Paper No. 3 suggests that this price is low as a long-term average, as compared to the real economic value of West Pakistan's gas resources, although it is about the price at which Sui gas is purchased, after purification, by the pipeline companies.

The Power Benefits of Tarbela and Shadow Prices

This discussion suggests that valuation of the costs and benefits of Tarbela in terms of current prices tends to lead to underestimation. In one sense it exaggerates them: Tarbela looks slightly less attractive when foreign exchange is valued at its scarcity price than when it is valued at the current official price. This is in line with what might be expected: all foreseeable power generation and transmission programs make intensive use of capital equipment purchased with foreign exchange, but programs including Tarbela involve somewhat greater use of foreign exchange and somewhat less use of locally available fuels.

Yet this would be misleading as a final conclusion, for fuel reserves are in many ways like a special portion of foreign exchange reserves: while they last they save on foreign exchange (and the great expansion in domestic fuel production in West Pakistan in the last 10 years has resulted in large savings of foreign exchange), but when they are exhausted then foreign exchange must again be spent on fuel. When we attempt to go beyond the present apparent abundance of gas in West Pakistan and take this foreign exchange aspect of domestic fuel reserves into account, then the balance swings the other way and the estimate of Tarbela benefits made at current fuel prices seems less than it should be. The more reasonable estimate of the benefits on the basis of the wider view of the foreign exchange problem, therefore, appears to be something of the order of the $160 million (see Annex 2 to Supplemental Paper No. 1).

TABLE 7-8
PROGRAM WITH TARBELA AND THE CHEAPEST ALTERNATIVE WITHOUT TARBELA
PRESENT WORTH COSTS WITH FUEL VALUED AT CURRENT PRICES TO UTILITIES
($ million)

	Foreign Exchange Rate	
	Current	Shadow
	($1 = Rs. 4.76)	($1 = Rs. 9.52)
Cheapest Alternative	687	984
Program including Tarbela	569	877
Saving due to Tarbela	118	107

Figure 7-3 represents a decision-map with regard to Tarbela—or a plot of the combinations of shadow foreign exchange rates and shadow fuel prices at which Tarbela becomes preferable to a thermal (or Kunhar) alternative. It is based on the data presented in Figure 7-2 and upon the results of an additional calculation undertaken with a shadow foreign exchange rate of 1.6 times the current rate of

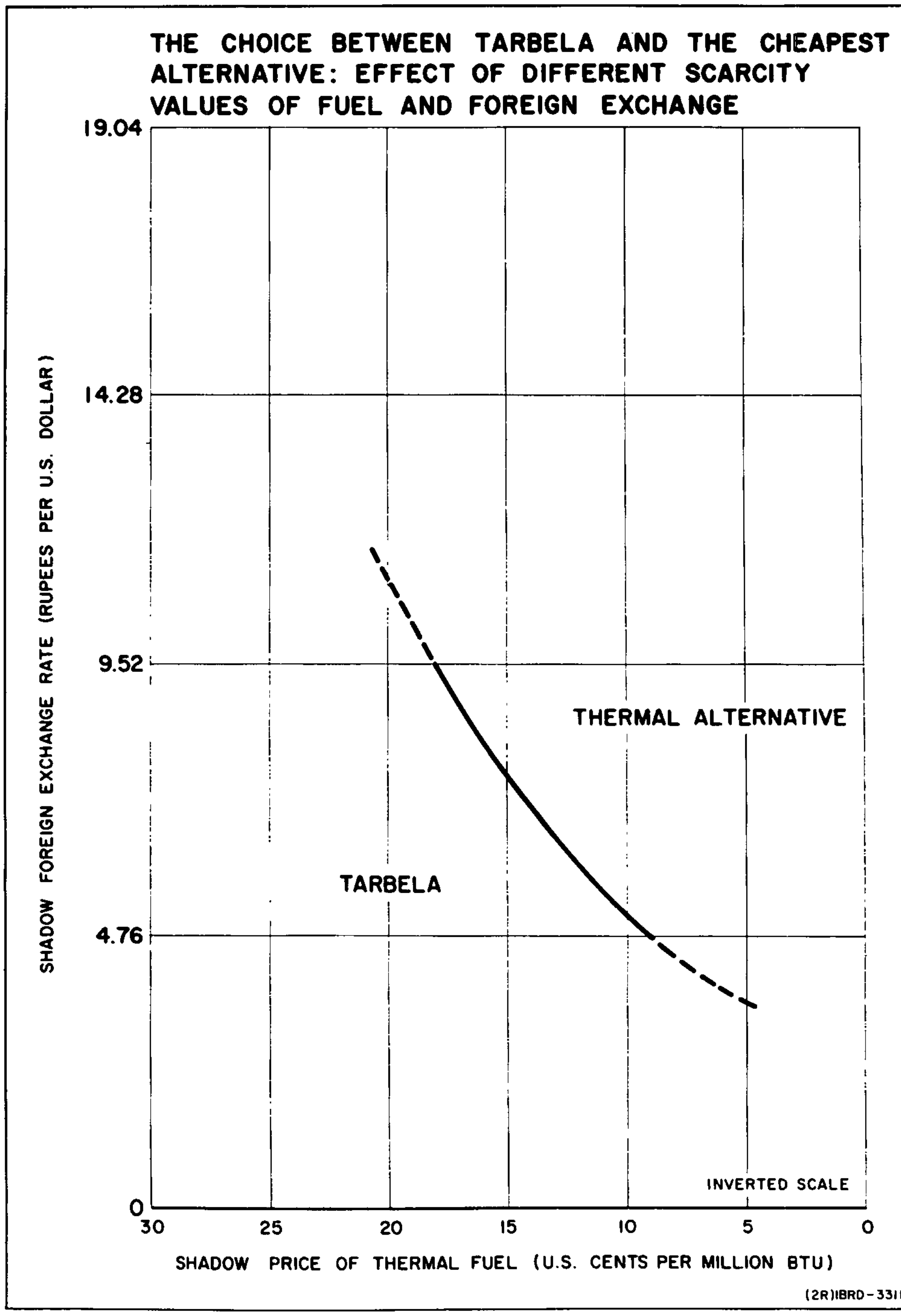


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FIGURE 7.3

Rs. 4.76 to the dollar (i.e. Rs. 7.6 per US dollar). The dashed lines represent extrapolations of the curve indicated by these three sets of calculations. The figure indicates that at the current foreign exchange rate a program including Tarbela is preferable to the cheapest alternative at thermal fuel prices above 9 cents per million Btu, while at double the current exchange rate a program with Tarbela is preferable to the cheapest alternative at any fuel price above about 18 cents per million Btu. The figure also indicates the sensitivity of the preference for Tarbela to changes in assumption regarding the foreign exchange rate.

Interconnection is discussed at length in Supplemental Paper No. 8, but it is clear from Figure 7-2 that the mere appearance of Tarbela on the system is scarcely sufficient by itself to justify interconnection. It must be recalled that the costs of the programs cited here do not include the costs of pipelines needed to carry fuel to the market; and all fuel is priced uniformly wherever it is used. On this basis, the programs which include Tarbela with interconnection have only a very slight edge on programs without interconnection. However, these simple figures do show that the advantage of interconnection tends to be greater, the higher the value attached to fuel. This tendency is in line with what might be expected: the greater the value of fuel the greater advantage there is in saving thermal fuel by widening the market for hydro energy.

A Second Approach: The Timing of Tarbela

The results shown in the last paragraphs, while they are derived for a program which includes Tarbela in 1975, do not show specifically what would be lost or gained by completion of Tarbela in 1975 rather than a few years later. They are useful in that they represent a recomputation in terms of economic prices, of the benefits of Tarbela, using much the same concept of benefits as used by the power consultant in his 1964 report on Tarbela. They are therefore comparable with these benefits and they are relevant for comparisons such as that between a joint stored water and power program involving Tarbela and an alternative involving, say, the Kalabagh-with-sluicing scheme.

For an investigation of the correct timing of the Tarbela Project, on the other hand, more explicit consideration has to be given to the time-path of scarcity values of inputs, particularly fuel, and to the exact alternative means of meeting irrigation requirements—as well as power requirements. A reasonable degree of postponement for purposes of this type of analysis seemed to be about ten years—not so long as to exaggerate what could be lost by a certain postponement and not so short as to be meaningless, given the rather rough analytical tools at our disposal. Therefore, the following comparison is between a program involving completion of Tarbela Dam in 1975 and one involving its completion in 1985. The alternatives on the irrigation side are discussed in detail in Supplemental Paper No. 4, which covers the linear programming exercise. However, the main effects of a postponement of Tarbela from both the irrigation and the power points of view may be summarized here as follows:

1. A very much larger draft on the Province's reserves of natural gas for purpose of power generation between now and 1985: about 1.57 trillion Btu for a program including postponed Tarbela against about 0.87 trillion Btu for a program with Tarbela in 1975. This results largely from the fact that, given three factors—

the scarcity prices of fuel indicated in Supplemental Paper No. 3 for the period 1975–85, the assumption that Tarbela would anyway be coming on line in 1985, and the above analysis of the breakeven fuel prices at which Kunhar becomes attractive as an alternative to Tarbela—the power program for 1975–85 in the absence of Tarbela would be heavily thermal, consisting mainly of plants fired by Sui or Mari gas.

2. Loss of rabi irrigation supplies from Tarbela's live storage in the period 1975–85, a loss which it may be possible to make up by raising the Mangla Dam at an early date, by bringing in Sehwan-Manchar early and by installing deeper wells in fresh groundwater areas to mine the groundwater aquifer; this would result in lowering the groundwater table about 35 feet beyond what would be the case with the irrigation and agriculture consultant's balanced recharge criterion for tubewell pumping. These changes in the irrigation program would have effects upon the power program—the change in the full supply level and live storage capacity of Mangla would affect the power capability of Mangla during various months, and the overpumping would add to the power load, particularly in certain months of the rabi season.

3. In addition to these irrigation supply losses provided by Tarbela's interseasonal storage capability, there would be a loss of Tarbela's intraseasonal regulation capability for 10 years. It is hard to quantify this regulation capability because its actual importance will depend so much on the precise monthly and weekly pattern of irrigation requirements that develops and on the natural river flows actually experienced in the year in question, but it has been estimated that the amount of intraseasonal regulation provided by Tarbela during the rabi period of water shortage (November-April) would average about 1.8 MAF per year over 1975–85. Under mean-year conditions this intraseasonal regulation capability provided by main-stem storage is approximately equal to the combined regulation capability of Sehwan-Manchar and Chasma. Allowance is made in the irrigation program for the loss of Tarbela's regulation capability by bringing in Sehwan-Manchar earlier than would be necessary simply to meet stored water requirements.

4. Tarbela storage releases would add to the annual recharge of the aquifer and this recharge would be valuable in areas of fresh groundwater where it could be recovered by tubewells during the scarce-water period. However, this recharge would be largely compensated by provision of direct irrigation supplies from other sources (as outlined above) sufficient to compensate for the loss of Tarbela water. If Tarbela were built in 1975 then the live storage available in Tarbela (after allowance for sedimentation) would by 1985 be about 7.4 MAF, assuming a drawdown level of 1332 feet. On the IACA release pattern, availability of stored water during the November-April period would be about 95 percent of this or 7.05 MAF. The alternative sources mentioned under (2) above would make up an equivalent amount (calculated in rim-station equivalents): Raised Mangla (3.18 MAF), Sehwan-Manchar (2.10 MAF), and Overpumping (1.80 MAF). Provision of these rabi supplies would thus compensate for most of the valuable recharge that would have been provided by Tarbela releases.

Alternative Joint Storage/Power Programs

Thus it is possible to build up two alternative storage and power programs for the period 1965–2000, one including Tarbela in 1975, the other Tarbela in 1985, and both meeting projected requirements of irrigation water and electric power. The alternative power program, would, according to our studies, serve to meet projected power loads including the overpumping requirements while the alternative irrigation program would, according to the linear programming analysis, make it possible for West Pakistan to attain the same gross value of agricultural output in the reference years 1975 and 1985 as was found to be attainable with the completion of Tarbela by 1975. Tables 7-9 and 7-10 summarize the costs of the alternative programs.

Low Mangla and Chasma are not explicitly mentioned in these programs because Mangla is already close to completion and Chasma is common to all programs; so that neither would affect the comparison. The cost estimates of the storage projects included have been taken from the 1966 Gibb report on the Tarbela Project. The figure included for overpumping in the postponed Tarbela program is based on the assumption that the IACA target for tubewell installation between 1966 and 1975 of about 20,000 public tubewells will be achieved, though the location of some of the wells has been rearranged in order to establish by 1975 an overall pattern of tubewells better adapted to a situation in which Tarbela would not be completed until 1985.

Of the two power programs needed for this comparison, one was the program including Tarbela in 1975 and including systemwide interconnection in 1971 (Table 7-7), while the other was specially designed to be fully complementary with the irrigation storage program outlined in Table 7-10. Apart from the additional thermal capability required to make up for the absence of Tarbela, complementarity required two other important changes.

First, the load forecast for the later years had to be raised to cover the additional amounts of power required, both for pumping more water in the rabi season to make up for the lack of Tarbela and for pumping from a greater depth throughout the year as a result of lowering the water table. It was estimated that this might total about 280 million kwh (including distribution losses) in 1980 and about 550 million kwh (including losses) in 1985. This additional energy requirement was distributed over the canal commands where overpumping would be undertaken for supply of irrigation water from the groundwater aquifer. Monthly energy requirements were converted into peak loads by a 70 percent load factor—being about the average of the monthly load factors implied in the pumping load

TABLE 7–9
COST OF IRRIGATION PROGRAM INCLUDING TARBELA 1975
Present Worth at 8%
($ million)

		Current Exchange Rate ($1 = Rs. 4.76)	Shadow Exchange Rate ($1 = Rs. 9.52)
1975	Tarbela Dam	385	616
1980	Sehwan-Manchar	70	112
1988	Raised Mangla	34	54
		489	782

TABLE 7-10
IRRIGATION PROGRAM INCLUDING TARBELA 1985
($ million Present Worth at 8%)

		Current Exchange Rate ($1 = Rs. 4.76)	Shadow Exchange Rate ($1 = Rs. 9.52)
1975	Raised Mangla	93	148
1975	Sehwan-Manchar	98	164
1985	Tarbela	179	286
1975-85	Overpumping	102	116
		472	714

forecasts made by the Bank's consultants for the Northern Grid area in 1985. So as to err on the conservative side in assessment of the additional load, no allowance was made for interruption of the tubewell load. The result of these calculations was an addition to peak load in the critical months of March of 60 mw and May of 34 mw in 1980; and of 120 mw and 65 mw, respectively, in 1985.

Second, an allowance had to be made for the change in capabilities at Mangla that would result from raising it, and at the same time adjustment of the rule curve for the operation of the reservoir to a pattern that would be appropriate for a situation where some Mangla storage was being used to supply canal commands that would otherwise have been fed from the Indus. The basic approach was to develop a release pattern that was a combination of the agricultural consultant's release pattern for Mangla (applied to the 4.8 MAF live storage of Low Mangla, with drawdown level of 1040 feet) and the agricultural consultant's release pattern for Tarbela (applied to the 3.5 MAF live storage that would be added by the raising of Mangla). Adjustments had to be made, particularly during the filling period, to ensure that the outflow through the dam during this period would at least be sufficient to meet the kharif irrigation requirements of the Jhelum-fed canal commands. The rule curve finally adopted for the study was one that would provide sufficient kharif irrigation water in a mean year and at the same time fill most of the reservoir by early August. Storing such a large proportion of flows in June and July meant that energy available in those months was severely curtailed. In years of low summer flow, filling of the reservoir would have to be slower, which would mean that the capability would not increase as rapidly between the time of maximum drawdown (early May) and the end of the kharif season (September). Nevertheless, there seems to be little doubt, if the assumptions regarding irrigation requirements made by IACA are correct, that High Mangla could be filled, while at the same time the 1985 kharif requirements of the Jhelum-fed canal commands[1] were met, except, possibly, in years such as 1940 when kharif flows on both the Chenab and the Jhelum were unusually low.

As regards investment in the power sector, postponement of Tarbela from 1975 to 1985 would require installation of about 4,300 mw of new thermal capacity between 1966 and 1985—or about 1,100 mw more than the program with Tarbela

[1] As estimated by irrigation and agriculture consultants. IACA, Comprehensive Report, Volume 5, Annexure 7—Water Supply and Distribution, p. 94.

in 1975. The generation program modeled around delayed Tarbela is shown in Table 7-11. The majority of the additional capability required would be straight replacement of the Tarbela units (capability of 12 units with a 1332-foot drawdown level is about 875 mw in the critical period on the system), but part of it would also be (i) to meet the additional overpumping load, (ii) to cover the additional reserve requirements of thermal capability (12 percent reserves on thermal equipment as against 5 percent on hydro equipment), and (iii) to provide the additional reserves required if the system remained without interconnection.

With regard to the last point, attention was given to the question of whether, if Tarbela were expected in 1985, it would be preferable to introduce EHV transmission earlier and concentrate the requisite additional thermal capacity in the interim at Mari/Sui, or whether it would be better to build additional gas pipeline capacity from Sui and maintain the independence of the three main power markets. Inclusion of early interconnection in the program with postponed Tarbela would make possible some fuel savings as a result of providing a wider market for Mangla energy and it would enable the Tarbela units to be brought in more rapidly than would otherwise be the case after 1985; on the other hand, it would eliminate a sizeable part of the potential saving in capital costs that postponement of Tarbela could make possible. In fact, by 1985 loads in the North will, according to our load forecast, be large enough and they will be growing rapidly enough that the output of the 12 Tarbela units could be almost fully absorbed within the North alone

TABLE 7-11
POWER DEVELOPMENT PROGRAM FOR NORTHERN GRID WITH TARBELA POSTPONED TO 1985
(Mari and South as in Table 7-5)

	System Additions		Thermal Capability (mw)	Hydro Capability (mw)	Total Capability (mw)	Peak Load (mw)
1966	Existing		302	165	467	513(Oct)
1967	Lyallpur S 1	(124)	302	155	457	513(Jan)
	Mangla 1 & 2	(90)				
1968	Lahore GT 2	(26)	478	265	743	598(Mar)
	Lahore GT 3	(26)				
1969	Mangla 3	(45)	478	310	788	690(Mar)
1970	Mangla 4	(45)	578	355	933	813(Mar)
	Lyallpur P	(100)				
1971	Lyallpur P 1	(100)	663	355	1,018	909(Mar)
	Retire	(15)				
1972	Mangla 5 & 6	(90)	663	445	1,108	1,004(Mar)
1973	Lyallpur P 2	(100)	763	445	1,208	1,099(Mar)
1974	Mangla 7 & 8	(90)	763	535	1,298	1,196(Mar)
1975	Raised Mangla		763	685	1,448	1,227(May)
1976			763	685	1,448	1,334(May)
1977	Warsak 5 & 6	(w/o re-reg.)	863	825	1,688	1,520(Mar)
	Lyallpur 3	(100)				
1978	Lyallpur 4	(100)	963	825	1,788	1,641(Mar)
1979	Lyallpur 5	(150)	1,113	825	1,938	1,758(Mar)
1980	Lyallpur 5a	(150)	1,263	765	2,028	1,847(May)
1981	Lyallpur 6	(200)	1,463	765	2,228	1,991(May)
1982	Lyallpur 6a	(200)	1,663	765	2,428	2,140(May)
1983	Lyallpur 7	(200)	1,863	765	2,628	2,300(May)
1984	Lyallpur 7a	(200)	2,063	765	2,828	2,455(May)
1985	Lyallpur 5b	(150)	2,213	765	2,978	2,632(May)

within about five years. Rough calculations to take account of these points, and of the saving in gas pipeline capacity and reserve generating capability that would be possible with interconnection, suggested that it would be economically preferable to eliminate interconnection altogether if Tarbela were not available until 1985.

These calculations regarding interconnection, like the other calculations concerning the timing of Tarbela, were conducted in terms of the economic fuel prices developed in Supplemental Paper No. 8 specifically for the two cases—of Tarbela in 1975 and Tarbela in 1985. Use of the economic fuel prices, in conjunction with the assumption that interconnection would not be introduced in the postponed Tarbela case, required that an allowance be made for the capital and operating costs of gas pipeline capacity needed to carry the gas from Sui to the power markets. Analysis of the pattern of fuel requirements in the Northern Grid area in the case with postponed Tarbela suggested that, if all fuel requirements were to be met from gas, the annual load factor on the gas pipeline supplying the thermal plants would be quite high—about 85 percent in 1984, for instance. The cheapest way of making sufficient fuel available would therefore probably be, as far as can now be foreseen, to provide enough gas pipeline capacity to meet peak-day requirements. Without Tarbela in 1975, peak-day requirements of gas for thermal generation in the Northern Grid would rise from 75 MMcf in 1967 to about 80 MMcf in 1971 and 100 MMcf in 1976 (quite slowly because most capacity additions through this period would be hydro units). Peak-day requirements would rise more rapidly after 1976 to about 200 MMcf in 1981 and above 300 MMcf by 1985. With Tarbela in 1975 peak-day requirements for thermal fuel would not rise above about 100 MMcf at any time through the 20-year Plan period. It is possible to make a rough estimate of the cost of providing this additional 200 MMcf per day of pipeline capacity, required by the program with postponed Tarbela, on the basis of the latest expansion plan prepared by the company responsible for the Sui-Multan-Lyallpur gas pipeline, Sui Northern Gas Pipelines Limited.[1] It would appear that the total economic cost involved in providing loops and compression sufficient to meet this additional peak-day requirement would be in the neighborhood of $26 million, with a present worth of about $8 million at the current foreign exchange rate, and about $13 million at the shadow foreign exchange rate.

In addition to these pipeline investment costs there would also be certain smaller amounts involved in provision of additional gas purification facilities at Sui and in the operation and maintenance of these various gas facilities.

Gas pipeline requirements for the South would be about the same as required under the 'without interconnection' case discussed in Supplemental Paper 8. Peak-day gas requirements of the power programs with early Tarbela and with delayed Tarbela would start to diverge significantly about 1971/72 and the peak-day requirements of the program with delayed Tarbela would rise to over 200 MMcf in the late 1970's (i.e. before the major nuclear plants appeared in the early 1980's), while those of the program with early Tarbela would scarcely rise above 100 MMcf throughout the planning period and would generally be substantially lower. The economic cost of providing pipeline capacity to cope with the additional peak is

[1] Sui Northern Gas Pipelines Limited, Appraisal No. 3 of Cost and Viability for Pipeline Extensions to Daudkhel and Peshawar (October, 1966). This plan is discussed further in Supplemental Paper No. 8.

estimated in Paper No. 8 at about $23 million; the discounted present worth of these costs, together with the operation and maintenance costs for the pipeline, is estimated there at about $12 million at the current foreign exchange rate and $18 million at the higher foreign exchange rate. As pointed out in Supplemental Paper No. 8, if it proves possible to develop the Sari Sing field for gas storage, the differential between the two programs, in cost of facilities for making gas available to meet all thermal fuel requirements, would be somewhat greater because the difference between average-day fuel requirements of the two programs is greater than the difference between peak-day fuel requirements.

Table 7-12 shows the total system costs of the alternative power programs, including the pipeline costs just discussed, discounted to 1965. The costs shown in the table cover all capital and maintenance and operating costs of power generation and transmission for 1966–85, together with fuel requirements valued according to economic prices; they also cover the major differences in capital costs and fuel costs that would be involved in the period 1985–95 as a result of bringing in the Tarbela units in the years following 1985 instead of 1975–80. The costs are shown for the different assumptions with regard to the foreign exchange rate used in this report and for the different assumptions regarding fuel reserves (and hence fuel prices). It is possible to indicate briefly the main components of the cost of postponement. The difference between the present-worth costs of the two programs, when foreign exchange is valued at the current scarcity price and fuel at the price series appropriate on the basis of current estimates of gas reserves, is indicated in the Table 7-12 to be $116 million. In terms of the capital costs of generation and transmission over 1966–85 (with the foreign component valued at this higher exchange rate), the program with Tarbela in 1985 actually shows a substantial saving of about $110 million over the program with early Tarbela. The cost of additional thermal capacity required to make up for lack of Tarbela in 1975–85 is much more than outweighed by the capital cost savings obtained by eliminating the need for the EHV transmission system and by postponing the Tarbela units. The total costs involved in the construction and operation of the amount of gas pipeline capacity required for the postponed Tarbela program are estimated at about $35 million in present-worth terms, reducing the net capital cost saving over the period 1966–85 to about $75 million. And this saving is much more than offset by the combined effect of the additional fuel costs involved—about $155 million, two-thirds of it in the 1975–85 period—and the additional capital cost of about $36

TABLE 7–12
PRESENT-WORTH COSTS OF POWER PROGRAMS INCLUDING TARBELA IN 1975 AND IN 1985
($ million discounted at 8% to 1965, economic fuel prices)

	Current Estimated Gas Reserves		Larger Gas Reserves	
	Current Exchange Rate	Shadow Exchange Rate	Current Exchange Rate	Shadow Exchange Rate
Tarbela 1975	795	1,104	674	983
Tarbela 1985	915	1,220	767	1,072
Costs of 10-year Postponement	120	116	93	89

million involved for the postponed Tarbela program after 1985, by installing the Tarbela units instead of thermal units at that time. Thus, in summary, the net saving in capital costs over the whole period 1965–95 resulting from postponement of Tarbela is of the order of $40 million, and this is more than outweighed by the extra fuel costs of about $155 million incurred by such a postponement. Of these extra fuel costs about 70 percent is due to the extra quantity of thermal fuel required and about 30 percent due to the higher average price at which the fuel for the program with delayed Tarbela is costed here.

It is noteworthy how these figures for the benefits of having Tarbela early rather than late are much less sensitive to the foreign exchange rate used than were the estimates of the benefits of Tarbela given earlier on the basis of financial fuel prices and of fuel prices that were uniform throughout the Province and throughout the years of the planning period. The difference arises mainly as a result of the special approach to fuel pricing adopted in this analysis. The main alternative to Tarbela studied here as elsewhere is thermal equipment which is much cheaper in terms of capital cost, and hence in its direct foreign exchange component, but expensive in terms of the fuel it consumes. In the previous analyses indigenous fuel was treated as a purely domestic cost item so that comparison of programs with and without Tarbela showed significantly lower benefits to Tarbela when foreign costs were valued at an exchange rate higher than the official one. Here, however, fuel has been treated more like a foreign resource in that its price has been made to depend on the foreign exchange burden of importing fuel when known domestic fuel resources are exhausted. The heavier fuel consumption of the 'without Tarbela' (or in this analysis 'with postponed Tarbela') case weighs more heavily against it.

Present-Worth Costs of Alternative Joint Programs

The present-worth costs of the irrigation and complementary power programs developed in the preceding pages can now be brought together. The figures in Table 7-13 suggest that, at an economic fuel price based on the present estimates of gas reserves and at the scarcity value of foreign exchange used in this report, the cost of delaying the construction of Tarbela from 1975 to 1985 would be on the order of $50 million in present-worth terms. Even if gas reserves could be firmly assumed to be at the higher level, the cost of delay would still be substantial—at about $20 million. When foreign exchange expenditures are valued at the current official rate of exchange the costs involved in a delay of Tarbela from 1975 to 1985 appear considerably higher; the saving in the irrigation program from postponement of Tarbela is very small and the loss to power from postponement remains large. These results are chiefly due to the substantial overpumping required to help make up for the lack of Tarbela on the irrigation side and the heavy draft on natural gas reserves involved on the power side.

The validity of this comparison between alternative joint storage and power programs depends on the assumption that, if Tarbela were delayed, the alternative program could and would be implemented. The Study Group (cf. Supplemental Paper No. 4) believes that the alternative program is sufficiently valid as an alternative to be used in the economic evaluation of a postponement of Tarbela. Many of its components, such as High Mangla and the public tubewell schemes, have received considerable study in Pakistan. In combination they appear, in a preliminary way at least, to be capable of meeting the irrigation requirements projected by the irrigation consultant for the period 1975–85 even in years of low flow. It is true

TABLE 7–13
PRESENT-WORTH COSTS OF SURFACE STORAGE/POWER PROGRAMS
INCLUDING TARBELA IN 1975 OR 1985
($ million discounted at 8% to 1965, economic fuel prices)

	Current Estimated Gas Reserves		Larger Gas Reserves	
	Current Exchange Rate	Shadow Exchange Rate	Current Exchange Rate	Shadow Exchange Rate
Tarbela 1975				
Surface Storage Program[a]	489	782	489	782
Power Program	795	1,104	674	983
	1,284	1,886	1,163	1,765
Tarbela 1985				
Surface Storage[a b]	472	714	472	714
Power Program	915	1,220	767	1,072
	1,387	1,934	1,239	1,786
Saving Attributable to Completion of Tarbela in 1975 Instead of 1985	103	48	76	21

[a] Including all costs of main reservoir structures.
[b] Including some overpumping to compensate for lack of Tarbela.

that there seem to have been some historical years on the Jhelum when assumed kharif flows would have apparently been inadequate to fill High Mangla, if drawn down to 1040 feet as assumed here, while at the same time meeting the kharif irrigation requirements of the Jhelum-fed canal commands as projected by the irrigation consultant for 1985. However, even on assumptions other than those used by IACA, it appears to be reasonably certain that both the filling requirements and the kharif irrigation requirements could be fully met in the earlier years when the kharif irrigation requirements are smaller, and by the later years—say 1980–85—the extensive public tubewell fields will provide a sizeable amount of flexibility for coping with years of low flow.

While the Study Group believes that the alternative storage and power program is technically reasonable for purposes of economic comparison (cf. Supplemental Paper No. 4), the Study Group also believes that the Tarbela Project offers a degree of security that cannot be matched by alternatives. In the first place it has been extremely thoroughly investigated so that, once the decision is made to complete it, it can be anticipated with a fair degree of certainty that its contribution to power and to irrigation supplies will indeed become available eight or nine years later. In the second place, the project is inherently so large in its contribution to power supplies and to irrigation supplies that it provides a substantial margin for meeting unanticipated growth in demand.

In sum, then, the Study Group believes that the figure of $50 million, in present-worth terms, is a reasonable valuation of the savings to be had from completing Tarbela in 1975 rather than in 1985, except for the additional value that should be attached to the greater degree of security that adheres to the realization of the Tarbela Project. At the same time it should be borne in mind that the alternative program used as the basis for this comparison is the cheapest of several alternatives investigated and is also, in itself, a carefully coordinated whole. The figures presented, therefore, indicate the present worth of the additional costs incurred as a result of choosing the alternative program rather than the program with Tarbela in 1975. Interim delays in completion of Tarbela—of, say, five or six years—resulting from delays in final selection and financing of any coordinated program could result in much larger loss of benefits.

THE DRAWDOWN LEVEL AT TARBELA

By sacrificing about 600,000-700,000 acre-feet of live storage capacity and keeping the minimum reservoir level up to 1332 feet instead of the minimum design level of 1300 feet, the firm capability of 12 units at Tarbela can be increased by about 270 mw (cf. Supplemental Paper No. 6). The irrigation consultant's final Tarbela release pattern envisages maintaining about 5 percent of live storage in Tarbela beyond the first of May. Consequently, the period of minimum capability at Tarbela will occur at the end of May and beginning of June, before filling has commenced. However, according to the Study Group's calculations, early filling of Mangla Reservoir will increase the capability there by the end of May by a greater amount than the Tarbela capability will be reduced as a result of final releases. Therefore, with the reservoir release patterns and the pattern of monthly peak loads used in these studies, the critical period for the system as a whole will shift from late March to the first ten days of May after installation of the first four-six units at Tarbela. By Study Group estimates, the increase in firm capability at Tarbela in the first 10 days of May resulting from maintenance of the 1332-foot drawdown level instead of 1300 feet will be about 230 mw. Maintenance of such a drawdown level would also add substantially to the energy available from Tarbela in the critical period April-July (the end of rabi and beginning of the filling period); it would reduce the available energy slightly in the winter months November-March as a result of reduced releases. The net effect on the total amount of energy annually available from Tarbela with 12 units under mean-year conditions would be a slight increase from about 12,800 million kwh to about 13,100 million kwh.

The full 230 mw of additional capacity available with a drawdown level of 1,332 feet, as opposed to 1300 feet will, of course, only become available when all 12 units are installed. In the intervening period, the advantage of the higher drawdown level will be reaped in the form of some postponement of the need for investment in additional capacity. Once 12 units are installed, the saving in thermal capacity will be of the order of 250 mw, since firm hydro capacity requires somewhat lower percentage reserves than thermal capacity to provide the same degree of security of supply.

Several programs were analyzed using the computer simulation model with Tarbela at drawdowns to 1332 and 1300 feet. Table 7-14 gives partial details of four of them, focusing entirely on the differences brought about by the different drawdown levels. All are suboptimal in the sense that they would be improved by some rescheduling of the units. However, they are adequate for indicating the relative merits, from the power point of view, of maintaining a higher or lower drawdown over the years 1975–85. On the left-hand side of Table 7-14, there are two programs without interconnection and with a consequent delayed phasing of the Tarbela units. To meet the Northern Grid load additional thermal capacity is needed with a 1300 feet drawdown, adding up to about 300 mw by 1985. On the right-hand side of the table there are two programs with interconnection. A comparison between the two sides, incidentally, would not indicate the value of interconnection because they differ in other ways, in particular by including Kunhar at an earlier date than would likely be economically justifiable under foreseeable cir-

TABLE 7-14
Programs with Alternative Tarbela Drawdown Levels

	Without Interconnection					With Interconnection[a]				
	Tarbela: 1300 feet		Tarbela: 1332 feet			Tarbela: 1300 feet		Tarbela: 1332 feet		
	System Additions	System Capability (mw)	System Additions	System Capability (mw)	Northern Peak (mw)	System Additions	System Capability (mw)	System Additions	System Capability (mw)	Provincial Peak (mw)
1975	Existing	1,308	Existing	1,308		Existing	2,181	Existing	2,181	
	Tarbela 1 & 2 (160)	1,468	Tarbela 1 & 2 (180)	1,488	1,306(Mar)	Tarbela 1 & 2 (160)	2,341	Tarbela 1 &2 (180)	2,361	2,093(Mar)
1976	Tarbela 3 & 4 (160)	1,628	Tarbela 3 & 4 (180)	1,668	1,394(Mar)	Critical changes to May	2,467	Critical changes to May	2,543	2,243(May)
						Tarbela 3 & 4 (108)		Tarbela 3 & 4 (146)		
1977	Lyallpur 5 (150)	1,778		1,668	1,493(Mar)	Tarbela 5 & 6 (108)	2,775	Warsak 5 & 6 (80)	2,823	2,463(May)
						Korangi 5 (200)		Korangi 5 (200)		
1978		1,778	Mangla 7 & 8 (90)	1,758	1,601(Mar)	Warsak 5 & 6 (80)	2,963	Tarbela 5 & 6 (146)	2,969	2,712(May)
						Tarbela 7 & 8 (108)				
1979	Critical changes to May	1,824	Critical changes to May	1,840	1,671(May)	Tarbela 9 & 10 (108)	3,271	Tarbela 7 & 8 (146)	3,315	2,966(May)
	Warsak 5 & 6 (80)		Warsak 5 & 6 (80)			Korangi 6 (200)		Korangi 6 (200)		
1980	Mangla 7 & 8 (90)	2,064	Lyallpur 5 (150)	1,990	1,813(May)	Tarbela 11 & 12 (108)	3,582	Tarbela 9 & 10 (146)	3,607	3,250(May)
	Lyallpur 5a (150)					Kunhar 1 (203)		Tarbela 11 & 12 (146)		
1981	Tarbela 5 & 6 (108)	2,172	Tarbela 5 & 6 (146)	2,136	1,951(May)	Lyallpur 6 (200)	4,082	Kunhar 1 (203)	4,110	3,524(May)
						Korangi 7 (300)		Korangi 7 (300)		
1982	Tarbela 7 & 8 (108)	2,280	Tarbela 7 & 8 (146)	2,282	2,095(May)	Kunhar 2 (101)	4,183	Lyallpur 6 (200)	4,310	3,818(May)
1983	Lyallpur 5b (150)	2,430	Lyallpur 6 (200)	2,482	2,248(May)	Kunhar 3 (102)	4,685	Kunhar 2 (101)	4,811	4,165(May)
						Karachi N3 (400)		Karachi N3 (400)		
1984	Tarbela 9 & 10 (108)	2,738	Tarbela 9 & 10 (146)	2,628	2,398(May)	Kunhar 4 (85)	4,970	Kunhar 3 (102)	4,913	4,494(May)
	Lyallpur 6 (200)					Lyallpur 7 (200)				
1985	Tarbela 11 & 12 (108)	2,846	Tarbela 11 & 12 (146)	2,774	2,567(May)	Karachi N4 (400)	5,370	Kunhar 4 (85)	5,398	4,864(May)
								Karachi N4 (400)		
1985	(Total Thermal Cap.	1,513		1,213)		(Total thermal cap.	3,546		3,346)	

[a] Both these programs have the same transmission line scheduling:
1971 S/C 380-kv line Lyallpur-Mari-Karachi
1977 a duplicate of this line
1979 additional S/C 380-kv line Lyallpur-Mari

cumstances with regard to fuel. However, the two 'with interconnection' programs give a sound indication of the type of differences that would occur as a result of maintaining different drawdown levels at Tarbela in a power development program which included Province-wide interconnection. Because each Tarbela unit has a greater capability in the critical month with the higher drawdown level, the units can be brought in somewhat more slowly under those circumstances. Optimal scheduling would almost certainly further lengthen out the addition of units at Tarbela to permit absorption of more of their energy immediately as they are constructed. Nevertheless, the existence of interconnection would make it worthwhile to bring in the hydro units more quickly than would otherwise be the case. Less additional thermal capability is again required in the 'with interconnection' programs when Tarbela is held at 1332 feet than when it is drawn down to 1300 feet.

As pointed out in Paper No. 6, the benefits to power and to agriculture connected with different drawdown levels are likely to fluctuate considerably over the years, depending primarily on demand and supply for water and for power then existing, and on the feasibility and cost of increasing supplies of each from alternative sources. As a result, best use of resources probably would only occur if the drawdown level was frequently reconsidered and modified to accord with the situation expected to obtain in any particular year or series of years. Because demand and supply factors and the costs of alternative sources will likely change frequently, the series of years for which the drawdown level could wisely be set at some fixed level would be quite short.

The power programs outlined in Table 7-14 are based on the assumption that one or the other of the drawdown levels will be maintained through each year of the 10-year period, 1975–85. This period is certainly too long to be encompassed by one decision regarding the Tarbela drawdown level. Many changes will occur in the course of it. Initially, for instance, Tarbela will make available a rather large increase in supplies of rabi irrigation water; it will probably take some time for the farmers to absorb all of this increase and derive full benefits from it. Initially, in other words, the marginal value to agriculture of the 600,000-700,000 acre-feet of water lying between 1300 feet and 1332 feet will be relatively low. It should rise over the years—but then, according to the proposed irrigation program, additional surface water will become available from Sehwan-Manchar (in 1980) and there will be a large tubewell field in existence which can make available additional supplies of irrigation water relatively cheaply and easily by overpumping. Moreover, according to the projection of the economic value of thermal fuel the sacrifice involved in using more of the natural gas reserves for power generation at this time will be increasing quite rapidly. Thus there are far too many uncertainties and too many divergent trends foreseeable in the decade 1975–85 to warrant making a decision now about a matter which, being a matter of operating policy, does not have to be decided until much nearer the time.

The purpose of comparing these alternative power programs and considering complementary long-run irrigation programs is rather to give an impression of the general order of priority that now seems likely to attach to the claims of agriculture and of power in the decade 1975–85. The present-worth costs given in Table 7-15 refer simply to the costs over the period 1965–85; no allowance is made for a terminal correction, precisely because the intention is to focus narrowly on the 10-year period of choice being considered here. The table indicates that the benefits to power of maintaining the higher drawdown level throughout 1975–85 are not very sensitive to changes in the cost of thermal fuel[1] but are highly sensitive to changes in the value of foreign exchange. This is logical in view of the fact that maintenance of the higher drawdown adds little to the availability of useful energy from Tarbela but contributes significantly to capability in the critical period on the system. The saving from maintaining the higher drawdown is largely a saving of investment in complementary thermal capacity; and such saving has an important 60-80 percent foreign exchange component.

The table suggests that, whatever the value attached to the economic parameters, the higher drawdown is somewhat more valuable when the market for power is enlarged by systemwide interconnection. This is quite realistic considering that a portion of the benefit of the higher drawdown is, so to speak, attached to each unit and that, as pointed out, interconnection will make it worthwhile to introduce the units more quickly than would otherwise be the case. Earlier realization of the benefits will make for greater present worth. The very delayed phasing of the Tarbela units in the 'without interconnection' case thus means that the value attributed to the higher drawdown level in that comparison is a minimum estimate of the true value. On the other hand, the higher values resulting from the comparison of the 'with interconnection' cases result partly from the more rapid introduction of hydro units that interconnection will indeed make worthwhile, and partly from the fact that the next major addition to system capability following Tarbela is assumed in these programs to be the capital-intensive Kunhar Project—so even a slight postponement, such as is made possible by maintaining the higher drawdown level at Tarbela, results in significant savings. In fact, it does not seem likely that the fuel situation in the early 1980's will be sufficiently stringent to warrant bringing in Kunhar rapidly after completion of 12 units at Tarbela; it is more likely that

[1] The lower array of figures gives a better impression of sensitivity to fuel price than the top array because the latter is based on comparison of programs which are so heavily hydro-based (including Kunhar) that the energy lost through drawing down Tarbela to 1300 feet rather than 1332 feet is mostly compensated by absorbing more Kunhar energy. They are, in effect, programs which implicitly assume that fuel is very costly (see discussion at beginning of this Paper).

TABLE 7–15

PRESENT-WORTH SAVINGS TO POWER FROM OPERATING TARBELA RESERVOIR TO DRAWDOWN 1332 FEET RATHER THAN 1300 FEET OVER 1975–85

($ million)

	Current Exchange Rate			Higher Exchange Rate		
	Financial Fuel Prices	All Thermal Fuel per Million Btu		Financial Fuel Prices	All Thermal Fuel per Million Btu	
		20¢	70¢		20¢	70¢
Total System Costs of Programs with Interconnection						
With Tarbela 1300 feet	579	543	653	901	865	975
With Tarbela 1332 feet	558	522	631	867	831	940
Saving of 1332 feet over 1300 feet	21	21	22	34	34	35
Total System Costs of Programs Without Interconnection						
With Tarbela 1300 feet	556	497	649	852	792	946
With Tarbela 1332 feet	539	481	630	823	766	916
Saving of 1332 feet over 1300 feet	17	16	19	29	26	30

additions to capability at this time would be further thermal units which are far less capital-intensive than Kunhar; maintenance of the higher drawdown level would make it possible to postpone them, but the savings so obtained would be significantly less than the savings obtainable by postponing Kunhar. For this reason, the present-worth values of the benefits of maintaining the higher drawdown level derived from this comparison of programs including Kunhar should be considered maximum estimates.

On the basis of these various considerations it would appear that the best estimate of the value to power of maintaining the higher drawdown level at Tarbela from 1975 to 1985 would be about $19 million at the current foreign exchange rate.[1] This is the figure which is comparable with the estimate of agricultural benefits obtainable from releasing water down to 1,300 feet each year—the benefit estimates derived from the shadow prices implicit in the Study Group's linear programming analysis of agricultural investment. This linear programming analysis produces several figures for these benefits. In the first place, if the restrictive assumptions are made that Tarbela will be the only addition to surface storage in 1975–85, and that the tubewells will not pump more than balanced recharge in the mean year, then the value to agriculture of drawing down to 1300 rather than 1332 feet each year can be taken as the marginal benefits to agriculture accruing from the addition of 600,000-700,000 acre-feet of water to total rabi irrigation supplies each year; this is estimated at about $19 million in present-worth terms. But the linear program shows that this figure tends to exaggerate the advantages to agriculture of drawing down to 1300 feet in this period. First, it fails to take into account the growth of tubewell fields and the consequent possibility of making marginal additions to irrigation supplies by means of overpumping. Under these conditions, the marginal benefit to agriculture of drawing down to 1300 feet rather than 1332 feet should be counted in terms of the alternative cost of providing the water by overpumping rather than in terms of the absolute benefits such water could produce; this results in a present-worth figure of about $11-15 million. Secondly, the above analysis failed to take into account the Sehwan-Manchar Project, which the irrigation consultant recommended for completion by 1982. This project would add about 2.1 MAF rim-station equivalent to rabi irrigation supplies and therefore, if it were undertaken in 1982, it would substantially lower the marginal value of water released for agricultural purposes in the early 1980's.

On the basis of these figures for the power and agricultural benefits attaching to different drawdown levels, it appears there is a clear presumption in favor of operating Tarbela to a drawdown level of 1332 feet over the decade 1975–85. But, as pointed out, such a general prescription must in fact be checked, before actual operating decisions are made, on the basis of short periods of years. It is quite likely that there will be some years, for instance in the early part of the decade, when the drawdown level should be maintained higher than 1332 feet; this might enable the Tarbela units to be phased in a little more slowly than would otherwise be necessary. Equally there may be some years, e.g. just before Sehwan-Manchar is completed, when it would be justifiable to draw the reservoir down somewhat below 1332 feet. However, for purposes of preparing the power program recommended here, a normal operating level of 1332 feet has been assumed.

[1] This is based on the assumption that, as recommended in Supplemental Paper No. 8, the power system would be interconnected by 1975, so the Tarbela units would be brought in quite rapidly.

For the period after 1985, the critical factors affecting the decision regarding the drawdown level at Tarbela will be, again, the overall balance between supply and demand for irrigation water and for power as it exists at that time and the costs of the next projects in line for development of the irrigation system and the power system. Early completion of second-stage main-stem storage would tend to lower the marginal value of water for irrigation; delay might mean that it would be preferable to draw down below 1332 feet. However, it appears that there will be two factors prompting maintenance of a higher drawdown level. In the first place, the pattern of siltation at Tarbela is expected to be such that the addition to irrigation supplies obtained by drawing down to 1300 feet rather than 1332 feet will be continuously decreasing. (See the discussion in Supplemental Paper No. 6.) In the second place, as far as can now be foreseen, the economic value of thermal fuel consumed for power generation will be increasing through these years.

THE SCHEDULING OF INSTALLATION OF UNITS AT TARBELA

A number of different power programs with different schedulings of the Tarbela units were constructed and tested on the power system simulation model. They suggested that the best schedule might be to bring in the first four units immediately following completion of the dam (i.e., two in 1975 and two in 1976) and to bring in the remaining eight units in 1978–80. The 'gap' between 1976 and 1978 would be filled with the two Warsak units (5 and 6) for peaking purposes and with a 200-mw steam unit in the Mari area. These results were built into the power program recommended.

These recommendations regarding the scheduling of the Tarbela units diverge somewhat from those made by S&W most importantly in envisaging installation of the last four units at Tarbela in 1980 instead of in 1982/83. Precise scheduling will of course depend on details of the growth of system loads and of the disposition of loads across the Province; these details are not foreseeable at the present time. Nevertheless, it is worth describing briefly one of the exercises which led the Study Group to conclude in favor of early completion of Tarbela Units 9-12 because it indicates the method adopted for reaching judgments regarding the scheduling of the other units and because it illustrates the use of the power system simulation model for this type of analysis.

To test the scheduling of Tarbela Units 9-12, two power development programs were devised, identical in every way, except that one included Tarbela Units 9-12 and the third Mari-Lyallpur EHV transmission line in 1980 and 300 mw of Mari thermal capability in 1984, while the other included the same items but in reverse order—i.e., 300 mw of Mari thermal capability in 1980 and Tarbela Units 9-12 together with the third Mari-Lyallpur EHV transmission line in 1984. The present-worth costs of these alternative power programs are shown in Table 7-16. As might be expected, the savings attaching to completion of Tarbela Units 9-12 in 1980 rather than in 1984 are greater the higher the price of thermal fuel and the lower the price of foreign exchange. At the current foreign exchange rate, Tarbela Units 9-12 in 1980 always appear preferable to the Mari units, within the range of fuel prices considered. At the higher foreign exchange rate, there is little to choose at financial fuel prices or at low uniform prices for fuel. If the cost figures in the last two columns of Table 7-16 were drawn up on a graph similar to Figures 7.1 and 7.2 (at the beginning of this Paper), they would indicate increasing savings attaching to early scheduling of Tarbela Units 9-12 as the fuel price increased from

TABLE 7-16
PRESENT-WORTH COSTS OF PROGRAMS WITH TARBELA UNITS 9-12 IN 1980 OR IN 1984[a]
($ million)

	Current Exchange Rate			Shadow Exchange Rate		
	Financial Fuel Prices	All Thermal Fuel per Million Btu		Financial Fuel Prices	All Thermal Fuel per Million Btu	
		20¢	70¢		20¢	70¢
Program including:						
Tarbela 9-12 in 1984	512	482	612	794	764	895
Tarbela 9-12 in 1980	509	479	597	794	764	883
Saving of Tarbela 9-12 in 1980 rather than in 1984	3	3	15	0	0	12

[a] These figures represent total system costs over the period 1966-85. No allowance has been made for a terminal correction because it would be identical in the two cases, the structure of assets at the end of the planning period being the same in each.

20 cents to 70 cents per million Btu. The estimate of scarcity values of fuel showed that, on the basis of current estimates of gas reserves, the economic price of gas at well-head in the early 1980's would be in the range of 30-35 cents per million Btu. At such a price, it would clearly be preferable to have Tarbela Units 9-12 in 1980 rather than 1984; the saving obtained would be in the order of $2 million. Therefore, these units were scheduled for 1980 in the program presented in Volume I. However, if fuel reserves turn out to be larger than presently believed, then the conclusion might be different. The lower set of fuel prices developed on the assumption of somewhat larger gas reserves indicate a scarcity value for gas devoted to thermal generation in the order of 20 cents per million Btu in the 1980–83 period. The figures in Table 7-16 suggest that, with fuel available at that price, there would be no great advantage either to having the last Tarbela units in 1980 or to having them in 1984.

The conclusions outlined in the above paragraph were also tested, with the aid of the simulation model, under a number of other assumptions. For instance, the programs were examined to see if it was the presence of the third transmission line from Mari to Lyallpur in 1980 which made the earlier scheduling of the Tarbela units seem preferable. Various programs were run to examine different phasings of the transmission lines. The conclusion was drawn that, while there were advantages to having the third Mari-Lyallpur transmission line slightly earlier than recommended by S&W, this was not in fact the critical difference between the two programs with different schedulings of Tarbela Units 9-12. The scheduling of the last units at Tarbela was also tested in programs designed to meet the Higher Load Forecast that the Study Group also used for the Northern Grid area. The conclusions drawn from that study: the advantages of having Tarbela 9-12 early were then slightly greater than they were with the main load forecast used for these studies; however, if Kunhar were also brought within the planning period as a means of meeting these higher Northern Grid loads, then there were advantages to postponing the last units at Tarbela except at very high fuel prices (upwards of 70 cents per million Btu). The correct conclusion thus appears to be that, with loads and economic fuel values in the ranges that can now be foreseen for the early 1980's, early scheduling of the last units at Tarbela and postponement of Kunhar, at least into the late 1980's, would be the best course.

SUPPLEMENTAL PAPER VIII

Energy Transmission: EHV Interconnection and Gas Pipelines

Following the question of Tarbela, the second most important decision regarding the electric power system in West Pakistan concerned bulk transmission. A considerable amount of attention was given to this question both by Stone & Webster and by WAPDA's consultants, Harza Engineering Company. Another closely related matter which is also important in long-term planning is the amount of gas pipeline capacity that will be required to meet the needs of the electric utilities. WAPDA and the Karachi area power supplier KESC have prepared several estimates of their future gas requirements to assist the planning of the gas transmission companies, Sui Northern Gas Pipelines Limited for the area north of Sui, and Sui Gas Transmission Company Limited for the area to the south. This Paper is concerned with trying to identify the best overall pattern for the development of electrical transmission and gas transmission for the generation of electric power.

THE EXISTING SITUATION

West Pakistan has two large electric load concentrations—the Northern Grid (1965 gross peak of about 470 mw including 40 mw allowance for load shed) and Karachi (1965 gross peak of about 130 mw). There are two other relatively smaller load centers—Hyderabad or Lower Sind (1965 gross peak of about 30 mw) and Sukkur or Upper Sind (1965 gross peak of about 5 mw)—which are located between the Northern Grid area and Karachi. While the Northern Grid extends over 500 miles north and south, about 60 percent of the load is contained in a belt 100 miles wide extending from Lahore to 25 miles west of Lyallpur. The electrical load center for the Northern Grid is located just northeast of Lyallpur, the Karachi load is concentrated within a 15-mile radius. These two main load centers are separated by 575 air miles.

While the four load concentrations are not electrically connected, they are all served by gas pipelines emanating from the Sui field in the Upper Sind area. The Northern Grid area is tied together electrically by an eight-year-old 132-kv line connecting Warsak, Malakand, and Dargai hydro plants in the northwest with load centers along the Rawalpindi-Lahore and Sargodha-Lyallpur load axes. WAPDA's main thermal plant at Multan, to the south of the main grid, is linked to it by a 220-kv line. The Multan plant, in turn, is linked to the Sui gas field by a 16-inch pipeline completed in 1958. In 1965, about 60 percent of the electric energy supplied to the Northern Grid area came from the hydroelectric plants and about 40 percent from the Multan thermal station. During 1965, the Sui gas pipeline was extended from Multan to Lyallpur, and WAPDA's new thermal station at Lyallpur will burn Sui gas. The other electrical systems in West Pakistan are entirely dependent on thermal generation; they are all situated along the 16-inch Sui gas pipeline which extends from the Sui field to Karachi and they draw on the pipeline for almost all of their fuel requirements. Electrical transmission in the Upper Sind area is by means of 66-kv lines which radiate out from the new thermal station at Sukkur. The lines in the Lower Sind area operate at 34.5 kv and are centered on the new thermal plant in Hyderabad. The city of Karachi is encircled by a 66-kv loop, to which the new Korangi station is linked by two single-circuit 132-kv lines. A double-circuit steel tower line extending eastwards 18 miles towards Dhabeji is nearing completion. This line will operate at 66 kv but is designed for future 132-kv use. A decision by KESC and WAPDA to extend it the further 50-60 miles to Hyderabad/Kotri is understood to be imminent, and, as pointed out in Volume One, the existence of this line has been assumed in most of these studies.

Stone & Webster Proposals

In their report, S&W recommended that these four load centers should be interconnected in the early 1970's by a 380-kv transmission system; it would be extended to Tarbela in 1974. The first link they recommended, between Karachi and Mari in 1971, would enable Karachi to take advantage of the cheap gas believed to be available at Mari; this link also eliminates the need for the addition of further thermal capacity in Karachi between completion of the 125-mw Korangi C unit in 1969 and the time that the Pakistan Atomic Energy Commission's Karachi nuclear plant assumes reliable operating status in 1971 and 1972. The second 380-kv line foreseen by S&W was between Mari and Lyallpur, coming into operation in 1973. Three main advantages were attributed to this line: it would make possible the transport of large quantities of hydro energy down to Karachi, thus saving on fuel there; it would save on investment in generating capacity by consolidating the reserves of all main load centers; and it would enable the North to draw on generators fired by cheap Mari gas rather than generators in the Northern Grid area fired by Sui gas for its power supplies at times of low hydro capability. Most of these factors would become important at a later date, but nevertheless S&W thought it would be desirable to link Mari and Lyallpur as early as 1973 to avoid more capacity investment in the North prior to the completion of Tarbela. As early as 1973, it would also be possible to take some excess hydro energy (from Mangla units 1-6) south in months when Mari power was not needed for the north. To enable the Mari-Karachi line to carry the excess hydro power from the North and, more especially, to provide sufficient security of supply—since Karachi would be drawing firm power from Mari by 1973/74—S&W recommended addition of a second single-circuit 380-kv line between Mari and Karachi in 1973. They also scheduled the first Tarbela-Lyallpur line in 1974. On their program, the lines between Tarbela and Lyallpur and between Lyallpur and Mari were duplicated by the addition of second single-circuit lines in 1977 when Tarbela Units 5 and 6 came in; and a further single-circuit line between these points was added in 1982/83 along with completion of the last four units at Tarbela.

Stone & Webster compared 380 kv and 500 kv as voltages for the transmission system and concluded that 380 kv was slightly cheaper and also had certain operating advantages. Their economic analysis took the form of cost-streaming the investment and operating expenditures involved in the development of the two systems between 1965 and 1985, and allowing credits to the 500-kv system in the later years for its ability to carry greater amounts of excess hydro energy and cheap Mari energy into Karachi than could be carried by the 380-kv system. Discounting the net cost streams of the alternative systems at 8 percent, they found that the 380-kv system was about 11 percent cheaper in terms of present worth. On the economic side, S&W also felt that, since expenditures for the 380-kv system would arise in smaller blocks than for the 500-kv system, there was more chance of carrying through with the lower kv system. On the technical side, S&W also attributed a number of advantages to 380-kv. It was pointed out that by 1973/74 Karachi would be relying in the S&W generating program for firm capacity from Mari—and that this was an important part of the reason for adding a second 380-kv line between Mari and Karachi as early as 1973. A single 500-kv line could carry the load but it would not provide the same security, and two 500-kv lines at such an early stage would be very expensive. Introduction of either 380-kv or 500-kv transmission will initially cause difficult operating problems and require large quantities of reactive power generation; both should be less with 380 kv than with 500 kv. The lower voltage will also fit more easily into the existing transmission system; the existing 132-kv lines can be expanded to handle blocks of power delivered from the 380-kv line, whereas they might have to be at least partially replaced with 220-kv lines if 500-kv were made the main transmission voltage. Finally, S&W pointed out that the capacity of the 380-kv system could be increased as and when required by quite modest expenditures on series capacitors and intermediate switching stations on the longer sections of line; they estimate, for example, that the capacity of the Mari-Lyallpur line could be doubled by these means. Their program includes installation of one intermediate switching station at Moro to increase the capability and stability of the Mari-Karachi line.

Harza Proposals

Harza conducted detailed technical studies to identify stable transmission systems for West Pakistan and made economic studies to select among them.[1] Their schemes envisage an initial EHV line from Mari to Karachi in 1972 and a second EHV line from Mari to Lyallpur in 1973. They felt that a proper comparison between voltages could only be made over a longer period than 1965–85, and so they extended their analysis to 1990. They also took into account the heavier transmission losses that their technical studies showed would occur with a 380-kv system. Their economic studies include a large debit to 380-kv on account of transmission losses. Their analysis led to the conclusion that the relative merits of the alternative voltages in present-worth terms depended on the discount rate used. At rates below six percent, the 500-kv system was cheaper than the 380-kv system in present-worth terms. Between 6 percent and 8 percent, the present-worth costs of the two systems were quite similar. At interest rates above 8 percent, there was an increasing advantage to 380-kv. Their final judgment was that the balance of advantage lay with the higher voltage system. Their view was that, as manufactur-

[1] Harza Engineering Company, "West Pakistan Electric Power System Load Flow and Stability Studies" (August 1966), and "Economic Studies of EHV transmission for West Pakistan" (September 1966).

ing and operating experience with 500 kv is gained, its costs would come down more rapidly than those for the longer-established 380-kv voltage, and that loads might well grow more rapidly than they had projected, so that the lower voltage system would prove inadequate more quickly than presently anticipated.

STUDY GROUP'S EVALUATION

The S&W and Harza studies were based on the important assumption that sufficient gas would be available at Mari to support 1500-2000 mw of generating capability there. It now seems quite possible that this is not the case. This makes a sufficiently important change in basic assumptions to raise again the question of whether EHV interconnection should be introduced in West Pakistan in the 1970's. S&W have suggested that if indeed Mari cannot support more than 400 mw of capability (which is the view of this report, given the new estimates of gas reserves[1]) then it may be preferable to delay full development there until after 1975 and to keep the Karachi-Hyderabad and Northern Grid areas self-sufficient at least into the later 1970's. Given the uncertainty regarding gas reserves, the Study Group's studies focused mainly on the question of whether EHV interconnection should still be introduced even if there is a more limited reserve of gas at Mari, on when it should be introduced, and on the relationship between the construction of new transmission lines and the addition of generating units at Mangla and Tarbela. While detailed attention has not been given to the question of transmission voltage, the Study Group finds S&W's arguments persuasive and has in fact carried out most of its studies with 380-kv transmission systems.

Figure 7.2 of Supplemental Paper No. 7 which compared the present-worth costs at eight percent of power development programs including Tarbela with those of the cheapest alternative under different assumptions with regard to the price of thermal fuel suggested that the benefits of interconnection were quite sensitive to changes in assumptions regarding fuel prices and foreign exchange rate. The calculations presented in that figure were based on uniform fuel prices throughout West Pakistan. The figure implied that, with that assumption, a program including interconnection was preferable to one excluding interconnection when the fuel price was greater than 30 cents per million Btu if foreign exchange was valued at the current exchange rate, but when foreign exchange was attributed its scarcity value, then interconnection only became worthwhile if the fuel price was assumed to be greater than 30 cents per million Btu if foreign exchange was valued at the current exchange rate, but when foreign exchange was attributed its scarcity value, then interconnection only became worthwhile if the fuel price was assumed to be greater than 40 cents per million Btu.

To obtain a better grasp of the pros and cons of electrical interconnection between the power markets, additional studies were run on the basis of the two Tarbela programs mentioned above (Supplemental Paper No. 7, Tables 7-6 and 7-7) and a third program including Tarbela and interconnection, but based on the assumption that only 400 mw could be developed at Mari—as given in Table 8-1. It will be noticed that all three programs are very similar to one another, in that they all include two 400-mw nuclear units in Karachi in the early 1980's, all the hydro units at Warsak, Tarbela and Mangla discussed in the preceding Supplemental

[1] See Supplemental Paper No. 3, Annex 1.

TABLE 8–1
TARBELA WITH INTERCONNECTION AND 400 MW AT MARI
(DRAWDOWN LEVELS: TARBELA 1332 feet, Mangla 1040 feet)

	Northern Grid				Peak Loads			Mari		Hyderabad-Karachi		
	System Additions	Thermal Capab. (mw)	Hydro. Capab. (mw)	Total Capab. (mw)	North	Mari	South	System Additions	Capa-bility (mw)	System Additions	Capa-bility (mw)	Cumulative Total Sys. Capability
1966	Existing	302	165	467	513(Oct)	11(Oct)	194(Dec)	Existing	50	Existing	280	
1967	Lyallpur S1 (124)	302	155	457	513(Jan)	17(Oct)	225(Oct)		50	Hyderabad S2 (15)	307	
	Mangla 1 & 2 (90)									Kotri OFT (12)		
1968	Lahore GT 2 (26)	478	265	743	598(Mar)	22(Oct)	271(Oct)		50	Kotri GT (40)	347	
	Lahore GT 3 (26)											
1969	Mangla 3 (45)	478	310	788	690(Mar)	29(Oct)	321(Oct)		50	Korangi 3 (125)	472	
1970	Mangla 4 (45)	478	445	923	813(Mar)	45(Oct)	382(Oct)	Mari S1 (100)	150	Hyderabad GT 2 (26)	498	
	Mangla 5 & 6 (90)											
1971	Interconnect w. Mari	463	445	908		1,334(Mar)		Interconnect with N. & S.	250	Interconnect w. Mari	523	1,681
	(380 Kv)							Mari S2 (100)		(380 kv)		
	Retire: LYA S (10)									Karachi N1 (25)		
	MONT S (5)											
1972		463	445	908		1,501(Mar)			250	Karachi N1 (100)	623	1,781
1973		463	445	998		1,688(Mar)		Mari P (200)	450	Retire: KAR A (15)	608	1,966
1974	Mangla 7 & 8 (90)	463	535	998		1,877(Mar)			450		608	2,056
1975	Tarbela 1 & 2 (180)	463	715	1,178		2,093(Mar)			450	Korangi 4 (125)	733	2,361
1976	Tarbela 3 & 4 (180)	463	895	1,358		2,268(Mar)		Second interconnection	450	Second intercon-	733	2,541
								with S.		nection with Mari		
1977		463	895	1,358		2,475(Mar)			450	Korangi 5 (200)	933	2,741
1978	Critical Changes to May	463	977	1,440		2,712(May)			450	Korangi 6 (200)	1,133	3,023
	Warsak (80)											
1979	Tarbela 5 & 6 (146)	463	1,123	1,586		2,966(May)		Second interconnection	450	Korangi 7 (300)	1,433	3,469
	2nd interconnection w. Mari							with N. & S.				
1980	Tarbela 7 & 8 (146)	463	1,269	1,732		3,250(May)			450		1,433	3,615
1981	Tarbela 9 & 10 (146)	613	1,415	2,028		3,524(May)			450		1,433	3,911
	Lyallpur 5 (150)											
	3rd interconnection w.Mari											
1982		613	1,415	2,028		3,818(May)			450	Karachi N3 (400)	1,833	4,311
1983	Tarbela 11 & 12 (146)	813	1,561	2,374		4,165(May)			450		1,833	4,681
	Lyallpur 6 (200)											
1984		813	1,561	2,374		4,494(May)			450	Karachi N4 (400)	2,233	5,057
1985	Lyallpur 8 (300)	1,113	1,561	2,674		4,864(May)			450		2,233	5,357

Papers, and all other additions to generating capacity are assumed to be gas-fired thermal units. The scheduling of these various thermal and hydro units varies among the programs according to whether or not intermarket transmission is available and the amount of transmission capacity available. The 'without' interconnection' program includes 300 mw of capability at Mari, the new program introduced in this Supplemental Paper provides for 400 mw at Mari, and the old 'with interconnection' program included 1,100 mw at Mari. The two programs with limited development at Mari make up for the absence of capacity there with additional thermal units in the South (Hyderabad-Karachi) and the Northern Grid area fired by Sui gas. Both 'with interconnection' programs assume that the first step in interconnection will be construction of a 380-kv line all the way from Karachi to Lyallpur for operation in 1971.

Analysis with Financial Fuel Prices

The present-worth costs of these programs on the basis of financial prices for fuel, suggest that the program including interconnection and with 400 mw at Mari has a slight advantage over the 'without interconnection' program when foreign exchange costs are counted at the current rate—but almost none when foreign exchange is attributed its scarcity value. The program with 1,100 mw at Mari looks better but this is almost entirely due to greater use of Mari fuel, which, it will be recalled, is attributed a financial price of 14 cents per million Btu against (financial) prices of 36 cents for Sui fuel delivered to Karachi and 50 cents for Sui fuel delivered to the North. These figures appear to confirm the doubts raised by S&W about the value of interconnection in the absence of substantial reserves of cheap gas at Mari available for commitment to power. At the current foreign exchange rate and at financial fuel prices a program including interconnection looks marginally superior to one without it; but when foreign exchange is priced at a rate closer to its scarcity value the programs seem to have little advantage over one another—and then it is probably better to pick the one implying the smaller capital commitment, i.e. the program excluding interconnection.

Economic Fuel Prices

With these doubts thrown upon the validity of interconnection it appeared worthwhile to examine how the situation would look if the calculations were made in

TABLE 8–2
PRESENT-WORTH COSTS OF PROGRAMS WITH AND WITHOUT INTERCONNECTION AND DIFFERENT MW DEVELOPMENT AT MARI (FINANCIAL FUEL PRICES)
($ million discounted at 8 percent)

	Present-Worth of Total System Costs, 1966–2000	
	Current Exchange Rate	Shadow Exchange Rate
	($1 = Rs. 4.76)	($1 = Rs. 9.52)
Program		
Without Interconnection	577	872
With Interconnection and 400 mw at Mari	564	870
With Interconnection and 1,100 mw at Mari	554	858

terms of the economic prices for fuel developed in Supplemental Paper No. 3. Since all the programs considered here included Tarbela in 1975, the economic fuel prices calculated on that assumption were used. Because all programs include Tarbela in 1975, they also involve extremely little thermal fuel consumption in the North, especially after 1975. Not only would the total amount of thermal fuel consumed be small (of the order of 2-4 trillion Btu's per annum) but it would also be heavily concentrated in the two-four months in the spring when the energy available from the hydro plants is relatively small. Direct supply of much of this fuel by gas pipeline would involve an intolerably low load factor on the pipeline. Either gas storage facilities would have to be built or WAPDA would have to use imported fuel oil. This question is discussed at greater length below; here it is sufficient to say that for these reasons all thermal fuel requirements of the Northern Grid area in 1975–85 were assumed to be met from imported fuel oil (price delivered Lyallpur at the current scarcity rate of foreign exchange about 83 cents per million Btu). Thermal fuel supplies for the other conventional plants, whether located at Mari or in the South, were priced for this calculation at the appropriate prices for each year given in Supplemental Paper No. 3, Table 3-3. The calculations were made for both assumptions regarding the extent of natural gas reserves.

Gas Pipeline Capacity Requirements of Alternative Programs

Use of the economic wellhead prices for natural gas requires that a separate calculation be made, where appropriate, for the cost of transmitting gas from the Sui field to the location where it is to be used for power generation. This cost arises largely in the form of investments in gas pipeline capacity. The extent of capacity required depends, under present circumstances in West Pakistan, on peak-day gas requirements. Determination of these peak requirements is not simple. The advent of substantial hydro or nuclear capacity—to fill in base load—will materially alter the relationship between average-day gas requirements and peak-day gas requirements. Peak-month gas requirements of various programs under consideration can be derived fairly readily from the computer printouts. Peak-day requirements within these months have been derived by means of a formula which takes account of the (a) ratio between peak-day electrical energy requirements in a month and average daily energy requirements, and (b) the extent to which this energy is supplied from hydro, nuclear or, primarily for the South, Mari sources.[1] This formula allows for a tendency for gas-fired plants to be used more in peaking service; so that, the base daily gas requirements being smaller, daily fluctuations in gas requirements become more significant. Figure 8-1 shows the peak-day requirements of gas for power generation in the South implied by the program 'without interconnection' and 'with interconnection and 1,100 mw at Mari.' The figure also shows the average-day requirements of the two programs. The numbers underlying the figure are shown in Table 8-3, which also indicates the implicit annual load factors for the gas pipeline under the two different sets of assumptions.

The figure indicates the order of magnitude of the difference between the two power programs in peak-day gas requirements—rising steadily from 1970, the year before interconnection is assumed to come into being in the 'with interconnection' alternative to a maximum difference of about 120-130 MMcf per day by 1980.

[1] See Annex 8-2 for details of derivation.

Both peak and average day gas requirements of the 'without interconnection' program drop off sharply after 1980 as a result of the introduction of large nuclear units. Whereas the peak-day requirements rise steadily on the 'without interconnection' program until that time (except for the year 1972 which shows the impact of the Atomic Energy Commission's Karachi nuclear plant), the peaks fluctuate heavily on the 'with interconnection' program. The fluctuations arise from the in-

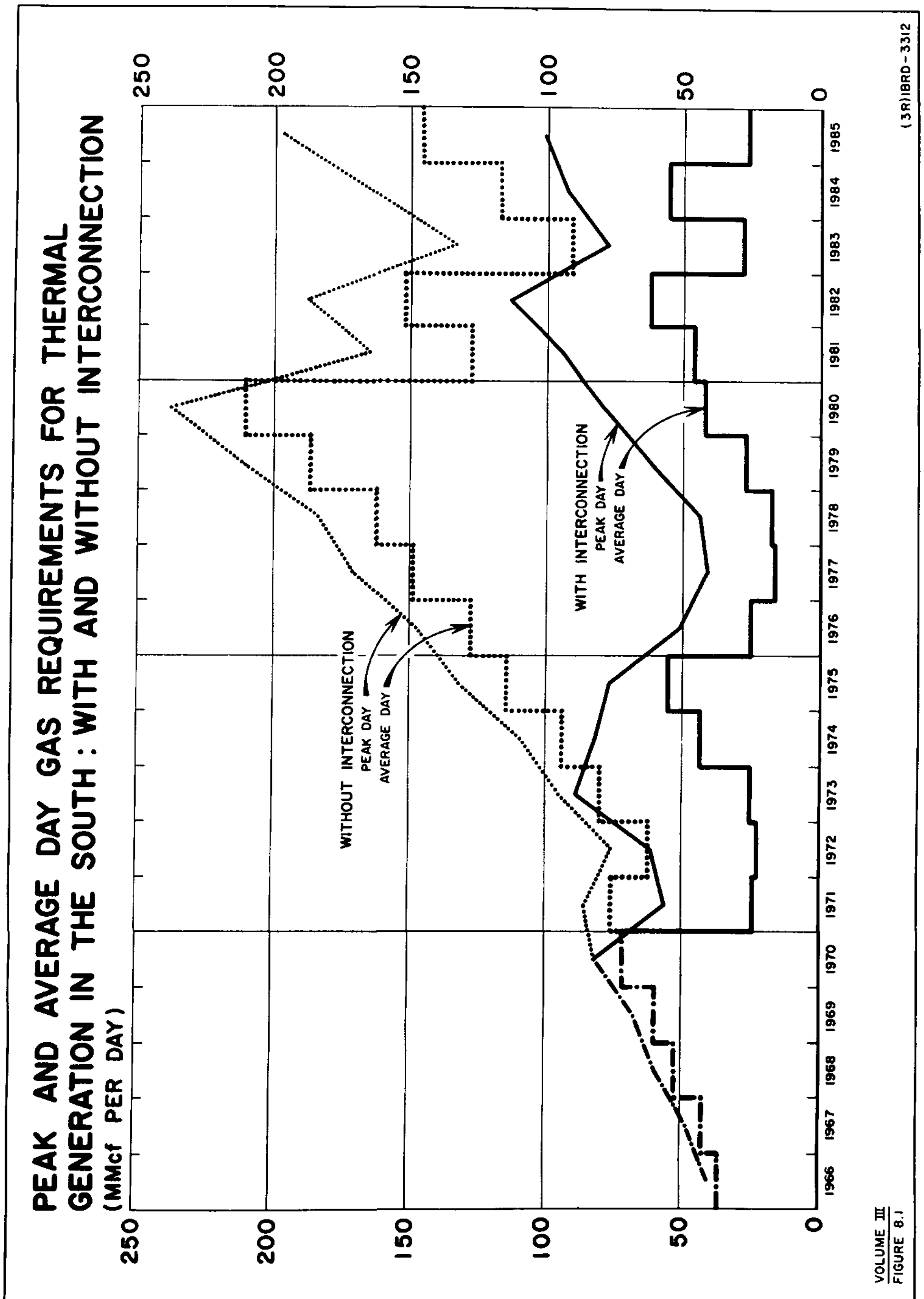

TABLE 8-3
GAS REQUIREMENTS FOR POWER GENERATION IN THE HYDERABAD-KARACHI AREA
THE IMPLICATIONS OF INTERCONNECTION

	Without Interconnection			With Interconnection and 1,100 mw at Mari		
	Average Day (MMcf)	Peak Day (MMcf)	Annual Load Factor (%)	Average Day (MMcf)	Peak Day (MMcf)	Annual Load Factor (%)
1966	36	40	90	36	40	90
1967	42	48	88	42	48	88
1968	52	59	88	52	59	88
1969	60	67	90	60	67	90
1970	72	82	88	72	82	88
1971	76	86	88	24	56	43
1972	62	76	82	23	61	38
1973	80	95	84	25	89	28
1974	94	109	86	43	82	52
1975	114	132	86	55	77	71
1976	128	148	86	25	51	49
1977	149	171	87	16	41	39
1978	162	184	88	17	44	39
1979	187	212	88	27	62	44
1980	210	238	88	42	79	53
1981	128	165	78	46	94	49
1982	152	188	81	62	113	55
1983	91	134	68	28	78	36
1984	117	165	71	55	93	59
1985	146	197	74	26	101	26

troduction of additional hydro units in the North or new Mari units and from the expansion of the transmission line, for each of these result in the increased availability to the South of cheap base-load energy which allows Sui gas-fired generation to play a reduced role; as a year passes and more of the hydro or Mari energy is absorbed in the North, the plants fired by Sui gas in the South take on again a larger portion of the load. But the Sui plants remain much more in peaking service in the 'with interconnection' case than in the 'without interconnection' case and so the load factor on the gas pipelines remains much worse, though it seldom drops below about 40 percent.

The cost of providing sufficient gas transmission capacity to cope with the peaks of the 'without interconnection' case can be roughly estimated, on the basis of expansion plans of the Sui Gas Transmission Company (SGTC), at about $23 million. SGTC has drawn up a number of alternative plans for expanding the capacity of the Sui-Karachi pipeline to meet anticipated needs up to 1975. These alternative plans are made up of varying amounts of compression and looping required to meet two alternative forecasts of the growth of demand for gas and under two different assumptions with regard to the pressure at which the gas initially enters the pipeline at Sui. One of the load forecasts represents an increase of demand for gas very similar to the difference between the peak-day requirements of the two alternative power programs around 1980—an increase in peak-day requirements of about 120-130 MMcf. The fact that a particular set of investments is required to expand the capacity of the pipeline by about 120 MMcf per peak-day over the coming 10 years does not of course mean that a similar program would be required to expand the capacity of the pipeline by the same amount in the decade 1970–80.

There are basically two means to expand the capacity of the pipeline—addition of compression and addition of loops to the pipeline. Given a certain size of pipe, addition of compression can provide quite substantial increases in capacity at relatively low initial cost. But there comes a stage when further compression adds little to capacity unless the pipeline is also looped. Looping, in contrast, provides relatively small initial increases in capacity at comparatively high cost, but as more loops are added, effectively duplicating the pipeline, so the ratio of increases in capacity to increases in capital expenditure improves. Plans for expansion have to be made therefore after a careful survey of prospective loads. If SGTC did have to be ready to meet the peak-day gas requirements implied by the 'without interconnection' power program in 1970–80, then it would probably substantially alter the expansion plan that it has prepared for the period 1966–75. However, our purpose here is not to identify exactly the means by which the gas pipeline might be expanded to meet projected needs; rather it is to obtain an indicative economic cost of the investment involved. Furthermore, in the long run, it matters less whether the particular expansion required to meet the utilities' requirements is best provided by addition of compression or by looping, for expansion of other (nonelectrical) demands would still at some stage require the one, providing the opportunity for further expansion by means of the other. Gulf Interstate Engineering Company of Houston, Texas, has actually prepared one long-term expansion program for SGTC designed to meet an overall system peak in 1985 of 380 MMcf.[1] This program is composed mainly of 20-inch and 24-inch looping—i.e. larger than the size of loops included in the actual expansion plan for the immediate future—and therefore requiring additional early capital outlay but producing economies in the long run. A figure of 380 MMcf for peak-day requirements in 1985 is considerably below the peak-day requirements that would be implied by addition of the electrical requirements of the 'without interconnection' power program to the projection of nonelectrical requirements in Supplemental Paper No. 3, Appendix Table 3-2.

For these reasons we have adopted the SGTC 130 MMcf/peak-day expansion program as a means of indicating the economic burden that would be involved in meeting the gas requirements of the 'without interconnection' program, but the resultant estimate should be taken as a minimum figure since it fails to allow for the heavy early investment in large-diameter loops that would probably be more economic in the long run for providing such a large expansion of capacity. Table 8-4 shows the items required by the SGTC expansion plan, assuming an intake pressure of 1070 psig at Sui, rescheduled to conform roughly to what would be required to meet the peak-day requirements of the electric utilities in the absence of interconnection. Thus, the evidence available suggests that meeting the gas requirements of electrical generation in the South without interconnection would require additional investment and pipeline operating expenditure of about $27 million, with a present worth of $12 million when foreign exchange is valued at the current rate and $18 million when foreign exchange is valued at twice the current rate.

[1] Gulf Interstate Engineering Company, System Study—Sui-Karachi Gas Pipeline for Sui Gas Transmission Company Limited (May 1965).

TABLE 8-4
ADDITIONAL PIPELINE INVESTMENT AND OPERATING COSTS INVOLVED IN WITHOUT INTERCONNECTION CASE
($ million)

		Capital Cost				Discounted at 8%	
		Foreign	Domestic	C & M Cost	Total	Current Exchange Rate	Shadow Exchange Rate
1973	2 × 1,100 HP compressors at HQ_3	0.7	0.3	0.1	1.1	0.6	1.0
1974	4 × 1,500 HP compressors at HQ_1	2.7	1.9	0.4	7.7	3.9	6.0
	43.5 miles 16″ loop Sui/HQ_1	1.5	1.2				
1975	56.5 miles 16″ loop HQ_1/HQ_2	2.1	1.5	0.6	5.0	2.3	3.6
	1 × 1,500 HP compressor at HQ_2	0.6	0.2				
1976	40.75 miles 16″ loop HQ_1/HQ_3	1.5	1.1	0.6	3.2	1.4	2.0
1977	1 × 1,100 HP compressor at HQ_3	0.2	0.2	0.6	3.3	1.3	1.9
	19.75 miles 16″ loop Sui/HQ_1	0.7	0.5				
	16 miles 16″ loop HQ_2/HQ_3	0.6	0.5				
1978	1 × 1,100 HP compressor at HQ_3	0.2	0.2	0.7	3.0	1.1	1.6
	29.5 miles 16″ loop Sui/HQ_3	1.1	0.8				
1979	45.2 miles 16″ HQ_2/Karachi	1.6	1.2	0.8	3.6	1.2	1.8
					26.9	11.8	17.9

POSSIBILITY OF GAS STORAGE AT SARI SING

There is a possibility that the gas pipeline may not need to be expanded to take care of peak-day requirements. It was pointed out in Supplemental Paper No. 3 that the Sari Sing gas field, located only about 20 miles from Karachi, is not now thought to contain substantial quantities of gas but might be usefully developed for storage of Sui gas. If that proves possible, then it may be necessary to expand the gas pipeline from Sui only to the extent necessary to cope with average day requirements; peak days or seasons would be met with a draft on Sari storage. However, if it is true that Sari Sing does not itself contain large reserves of gas and therefore could only serve usefully for peaking purposes, then the difference between the with and without interconnection cases in pipeline capacity requirements would in fact be greater than if gas from Sui must be provided directly to meet daily peaks. This results from the relatively high pipeline load factor in the 'without interconnection' case, on the one hand, and the rather low pipeline load factor in the 'with interconnection' case (see Table 8-3). Because of this discrepancy in load factors, the difference between the average-day gas requirements of the two programs is considerably greater than the difference in peak-day requirements. Therefore, the estimate of additional pipeline costs given above is on the low side if it can safely be assumed that Sari Sing can be cheaply developed into a storage facility.

Comparison of Total System Cost, 1965–85

With this estimate of differential gas transmission cost in hand, it is now possible to go on to compare the present worth of the total economic costs of the three programs mentioned above—'without interconnection,' 'with interconnection and 400 mw at Mari' and 'with interconnection and 1,100 mw at Mari.' Table 8-5 compares the costs of the programs, including differential gas transmission cost, with fuel evaluated in economic prices. All foreign exchange costs are here valued at the scarcity exchange rate. The comparison is limited to costs incurred over the 1965–1985 period. Viewing the figures in this Table there appears little to choose between the three alternative programs as a way of meeting West Pakistan's electric power requirements over the next 20 years. The only program which looks slightly worse than either of the others is the one that includes interconnection and develops only 400 mw at Mari; but even for this program the difference in cost is almost too small to be significant. It appears that the saving in thermal fuel and generating capability made possible by interconnection are just about offset in present-worth terms by the heavy early capital requirements of the EHV transmission itself. Or, looking at the comparison from the point of view of the 'without interconnection' case, one can say that the savings in transmission investment implicit in that program are just about offset in present-worth terms by the combined effects of the additional investment required in thermal plant and pipeline capacity and the additional thermal fuel costs. Only when the higher series of economic fuel prices, those implied by current estimates of reserves, are used, does the heavier use of fuel in the 'without interconnection' program show up to its detriment.

Effect of Differential in Fuel Costs After 1985

There is, however, one significant difference between the alternative power programs that cannot show up in a comparison limited to a 20-year period: this concerns the fuel costs that will be involved in running the equipment assumed in place in 1985 to meet the loads of the following years. It is hard to handle this problem in a precise way without an extension of the planning period being fed into the computer simulation model. Month-to-month load forecasts inevitably become more

TABLE 8-5
Present-Worth Costs of Three Alternative Patterns of Energy Development 1966–85
($ million, economic fuel prices, shadow exchange rate)

	Higher Fuel Price Series[a]	Lower Fuel Price Series[b]
With Gas Transmission and No Interconnection	791	759
With Interconnection and 1,100 mw at Mari	785	759
With Interconnection and 400 mw at Mari[c]	793	763

[a] Based on the assumption that total gas reserves are limited to 7,300 trillion Btu. See Supplemental Paper No. 3.
[b] Based on the assumption that total gas reserves are 9,500 trillion Btu.
[c] Details of the requirements of this program for gas pipeline capacity Sui-Karachi are not presented here, but the program would require about 40 MMcf/peak-day more pipeline capacity by 1978 than the program with more development at Mari, and the cost of this can be estimated from Table 8-4 at about $5 million in present-worth terms (using the higher foreign exchange rate). Appropriate allowances for the pipeline cost are included in the two figures presented in the table for this program.

and more speculative with each year they are pushed into the future. But the differences among programs regarding post-1985 operating costs appear to be sufficiently large for the essentials to be caught in a rough hand-calculation. By 1985, the program without interconnection is using about 40 percent more thermal fuel than the program with interconnection and 1,100 mw at Mari. Almost all this difference results from the fact that it is impossible without interconnection to absorb as much of the hydro power as can be absorbed with interconnection. By 1985, the 'with interconnection' programs are absorbing all but about 3,000 million kwh of the energy available from Tarbela and almost all of the excess occurs in the flood months from June through September. The 'without interconnection' program indicates an excess of 6,000 million kwh in 1985; and the excess occurs in most months of the year. A small amount of the difference in thermal fuel consumption also results from the saving in gas purification and transmission fuel and losses that result from using the gas at Mari; however, this is partly offset by the transmission loss involved when power generated at Mari is dispatched to the Northern or the Southern market.

In the years following 1985 the annual increments in consumption of hydro energy will be larger in absolute terms in the 'without interconnection' case than in 'with interconnection' case because, the excess being more distributed over the months, it can be absorbed more readily as the system grows. Nevertheless, absolute annual energy costs will remain higher in the 'without interconnection' case until all the hydro energy is absorbed. We estimate that this might occur about 1994 in the 'with interconnection' case and 1997 in the 'without interconnection' case.

A terminal correction has therefore been made to the figures presented above to allow for these varying trends in fuel cost after 1985 in the different programs. The terminal correction takes the form of projecting 1985 fuel costs for 15 years and subtracting from them allowances for the additional hydro energy absorbed in each year after 1985 (calculated at the appropriate 1985 economic fuel price and also discounted to 1965 at 8 percent). This does not, of course, allow in detail for the greater efficiency that may be expected of thermal plant added to the system after 1985 or for the trend in post-1985 economic fuel costs developed in Supplemental Paper No. 5. Nevertheless, it seems adequate to capture the fuel-cost implications of the systems assumed under the different programs to exist in 1985.

Table 8-6 presents the total system costs shown in Table 8-5 adjusted by this allowance for post-1985 fuel costs. The result is to show a somewhat clearer distinction among the programs considered. These figures suggest that there is a clear advantage to a program which includes interconnection and substantial thermal de-

TABLE 8–6
PRESENT-WORTH COSTS OF ALTERNATIVE PROGRAMS 1966–85 WITH ALLOWANCE FOR COSTS OF FUEL CONSUMPTION AFTER 1985
($ millions, economic fuel prices exchange rate)

	Higher Fuel Price Series	Lower Fuel Price Series
With Gas Transmission and No Interconnection	854	814
With Interconnection and 1,100 mw at Mari	835	804
With Interconnection and 400 mw at Mari	849	815

velopment in the Mari area. When thermal fuel is priced at rates appropriate to current estimates of reserves, this program shows savings with a present-worth value of about $20 million over the program excluding interconnection. The slower absorption of hydro energy without interconnection is a marked disadvantage to a program excluding interconnection. Even if fuel reserves turn out to be somewhat more plentiful, the best program with interconnection still has savings over the 'without interconnection' program valued at a present worth of about $10 million. The program which includes interconnection but develops only 400 mw at Mari, on the other hand, looks decidedly unattractive. The difference between the costs of this program and the one that concentrates thermal development at Mari is composed of two main portions: first, the extra pipeline investment required to take gas for thermal generation to the South, as noted before, and second, the extra fuel costs involved in thermal generation in the North under circumstances where it will probably not be economic to provide pipeline capacity. It was pointed out above that fuel requirements for thermal generation in the North after 1975 have been priced at the current economic price for fuel oil delivered there. The program with limited development at Mari compensates partly for lack of Mari capacity with more thermal development in the North, though not sufficient to make the North entirely self-sufficient. As a result, it suffers by comparison with a program which concentrates thermal development at Mari from the high price of fuel in the North.

On the basis of economic prices, therefore, this analysis tends to confirm the doubts raised by S&W about the validity of interconnection, if only 400 mw can be developed at Mari. If development has to be so limited there, then it is probably better to choose the 'without interconnection' program, which appears to cost much the same whether the cost is calculated in terms of economic prices (Table 8-6) or of financial prices (Table 8-2)—and which involves a much smaller capital commitment.

Possibility of Sui Gas-fired Plants at Gudu

In fact, limiting thermal development based on Mari gas to 400 mw would not necessarily mean that thermal development in the vicinity of Mari must be so limited. The economic prices developed in this report imply that substantial use should be made of West Pakistan's other gas reserves for thermal generation. At present, the chief reserves are in the Sui field. These may be used in the North or the South, as in our program with limited Mari development, or close to the gas field. Kuljian Corporation recommended that the best of several sites considered for Mari-based thermal generation was close to the Gudu Barrage, on the left bank of the Indus, where it could take advantage of the proximity of the river for water supplies.[1] This location is about midway between the Mari and the Sui gas fields. They estimated that the initial 45-mile 16-inch pipeline required to supply gas from Mari for a 125-mw thermal plant would cost about $5 million. This is presumably the financial cost, including duties and interest during construction. The economic cost, comparable with the cost figures used elsewhere in this report, is probably in the neighborhood of $4 million. The economic cost of looping the pipeline would

[1] Circulating water would be taken from the upstream side of the barrage and discharged below. Make-up water for the steam cycle would come from deep wells on site. Kuljian Corporation, "Report for Water and Power Development Authority, West Pakistan on Phase No. 1, Main Thermal Power Project, Two-66,000-kw Units."

be about $2.8 million. Assuming, therefore, that there would be no special difficulties in looping the section of the existing pipeline from Sui, which crosses the Gudu Barrage, one can infer that a 125-mw thermal plant at the Gudu Barrage could be provided with an adequate supply of Sui gas for a capital cost of about $3 million. These costs have a foreign exchange component of about 60 percent.

The program which excludes interconnection envisages development of 300 mw at Mari to meet local loads. The best 'with interconnection' program has 800 mw additional at Mari. On the basis of the prices given in the preceding paragraph the discounted present worth of the costs of linking these 800 mw to the Sui field may be estimated at about $10 million (using the shadow foreign exchange rate). However, this may not necessarily be a net addition to the costs of the program. Kuljian recommended direct use of Mari gas for thermal generation without purification. It is possible that purification of Sui gas could be foregone for short-distance transmission to the Gudu Barrage. Sulphur is the main noxious element eliminated in the purification and it might be possible to protect the relatively short pipeline involved from corrosion due to sulphur at low cost. Elimination of purification facilities for gas supplies to meet the needs of the additional 800-mw at Gudu would save several million dollars in present-worth terms (taking the economic cost of a purification bank at $1.9 million/60 MMcf per day capacity, and again basing calculations on a doubled foreign exchange component). However, disregarding this possibility, and allowing $10 million for additional pipeline facilities between Sui and Gudu, we can conclude that this would significantly reduce, but it would not eliminate, the present-worth cost advantages of the program with interconnection and heavy thermal development in the Mari area over the program without interconnection.

In summary, on the basis of conservative assumptions, this analysis has indicated present-worth savings to interconnection which are positive but small and which vary according to the different assumptions made with regard to the scarcity value of fuel and of foreign exchange. And as added argument, this analysis has not taken into account certain additional significant advantages which would result from interconnecting the main power markets of West Pakistan and concentrating thermal development at Gudu. The most important of these concerns the problem that will arise in the pre-Tarbela years in providing sufficient fuel for thermal generation in the Northern Grid area if that area has still to generate all its own power requirements at that time. The second involves the overall saving in thermal fuel over the next 20 years that interconnection will make possible by widening the market for hydroelectric energy. The third allows for the fact that the EHV transmission lines proposed may well be able to carry more hydro energy southward than has been conservatively assumed in the quantitative analyses underlying the preceding discussion. Fourthly, there are more general and intangible, but nonetheless important, advantages to interconnection such as the flexibility which it adds to the overall power system. These various matters are discussed in turn in the following paragraphs.

Problem of Fuel Supply for Low Load Factor Thermal Generation

If the Mangla and Tarbela Dams are drawn down every spring to meet agricultural requirements of irrigation water, their capacity to provide electric power will fluctuate considerably over the year—from a combined minimum of about 1,200 mw in April-May[1] to a combined maximum of about 3,600 mw in August. One consequence of this is that thermal installations in any areas supplied with hydroelectric power will generally have a rather poor annual load factor. This is particularly the case in the Northern Grid area. Analysis of the 'with interconnection' program on the power system simulation model suggests that the overall annual load factor on the thermal equipment existing or already sanctioned (i.e. excluding any additions to thermal capacity beyond the Lahore Gas Turbine envisaged for completion in March 1968) will be about 20-25 percent in each of the years 1969–74 and will be of the order of 10-15 percent in each of the years 1975–85. Without interconnection, the load factors would fluctuate considerably and they would sometimes be worse, according to the system dispatch performed by the simulation model.

It will be costly to supply fuel for low load factor operation of thermal equipment, and, because the 'without interconnection' program involves keeping the North self-sufficient in power even when the reservoirs are near their minimum levels, this problem will be more acute without interconnection than with it. Figure 8.2 shows the peak-day requirements for thermal fuel that our studies imply will occur over the years 1966–76 with and without interconnection and it compares these peaks with those projected by WAPDA and by SNGPL. The figure presents two 'with interconnection' cases, one based on the main load forecast underlying these studies and the other based on the higher load forecast prepared for the Northern Grid area. The SNGPL figures indicate the peak-day requirements of gas for power generation that SNGPL is preparing to meet. They represent the combined peaks of the Multan and Lyallpur steam stations only and are therefore not directly comparable with the so-called 'Study Group projections.' The WAPDA projections include, besides the requirements of the Multan and Lyallpur steam stations, also the requirements of the Lahore gas turbines, which SNGPL is not committed to meet. The WAPDA projections are therefore more directly comparable with the Study Group's projections, which cover all thermal fuel requirements of WAPDA Northern Grid stations except the small units at Lyallpur and Montgomery.

The figure indicates that the peak days are substantially higher without interconnection than with it, and it also suggests that WAPDA may be planning for higher peaks than may in fact he encountered. In regard to the first point, the figure brings out clearly the tendency that will exist without interconnection for peak days to fluctuate much more violently than with interconnection and the tendency for them generally to be higher. With interconnection between Mari and Lyallpur in 1971, the peak-day thermal fuel requirements of the Northern Grid area will not rise above the levels of 1966–67 before the late 1970's; but if interconnection is not provided at that time, then peak-day fuel requirements will rise, in terms of natural gas, from a level of about 60-70 MMcf in 1966 to about 100-120 MMcf in 1972–74. In regard to the second point, it is striking in the figure that the highest peaks projected in these studies (i.e. those of the 'without interconnection' case) are substantially below the peaks projected by WAPDA. Yet the dispatch performed by the computer simulation model and the formula used for

[1] Assuming drawdown levels of 1332 feet at Tarbela and 1040 feet at Mangla.

deriving peak-day gas requirements from it[1] should tend to exaggerate rather than to underestimate the peaks. There should, if anything, be a possibility of using the hydro plants to a greater extent for peaking than implied by the simulation model; transfer of thermal plant from peaking service to base load might tend to raise the average load on the machine, and it would certainly raise the load factor, but it would reduce the peak.

In view of the low load factor that will apparently prevail on thermal equipment in the North, if the system is run in such a way as to absorb as much hydro energy as possible, it is an open question whether it will remain economic to supply such a large proportion of WAPDA's fuel requirements as in the past in the form of gas. To meet the full peaks of the 'without interconnection' case in 1972–74 with direct supply from Sui would involve expanding the capacity of the pipeline by about 40 MMcf/day—at a cost of about $6 million in looping.[2] But the peak-day, average-day and load-factor figures which come out of the Study Group's comparative studies suggest that this would not be the best solution. A cheaper method of meeting sharp peaks would probably be to provide gas storage facilities. But there do not appear to be any suitable storage sites in the Northern Grid area. Therefore, it will probably be necessary to resort to fuel oil, expensive in foreign exchange and in costs of transport to the North, for meeting peaks and to continue to use some gas for meeting a relatively small base load. A detailed study would be required to tell exactly the shares that it would be most economic to allot to gas and to fuel oil. Nevertheless, it is possible to identify three disadvantages in this connection that would attach to a program without interconnection. The first two are illustrated in Table 8-7, which indicates the average and peak-day requirements of gas for thermal generation of programs with and without interconnection between 1971 and 1976.

First, as illustrated by Figure 8.2, the peak days of the 'without interconnection' program are generally higher, indicating a need for larger quantities of peaking fuel and facilities (transport and storage) for making it available. Second, the average days of the 'without interconnection' case are also substantially higher, suggesting that less of the existing pipeline capacity could be released to serve the requirements of other gas consumers. And third, though not shown by the annual figures in this table, the additional requirements of the 'without interconnection' case are

[1] See Annex 8-2.
[2] This rough figure is derived from the SNGPL study, Appraisal No. 3 of Cost and Viability for Pipeline Extensions to Daudkhel and Peshawar (October, 1966).

TABLE 8–7
THERMAL FUEL REQUIREMENTS IN THE NORTHERN GRID, 1971–76
(MMcf/day)

	With Interconnection		Without Interconnection	
	Average Day	Peak Day	Average Day	Peak Day
1971	15	71	23	80
1972	15	60	36	112
1973	12	66	24	97
1974	11	53	37	124
1975	11	64	14	87
1976	8	70	8	65

heavily concentrated in a few months in the year (mainly, the low-hydro months), so that most of them would in fact probably have to be met by 'peaking fuel' rather than by base-load gas. Thus, it is a marked advantage of a 'with interconnection' program, not fully taken into account in the quantitative economic analysis of the total costs of the alternative cases, that it reduces the amount of thermal generation that will be necessary in the North.

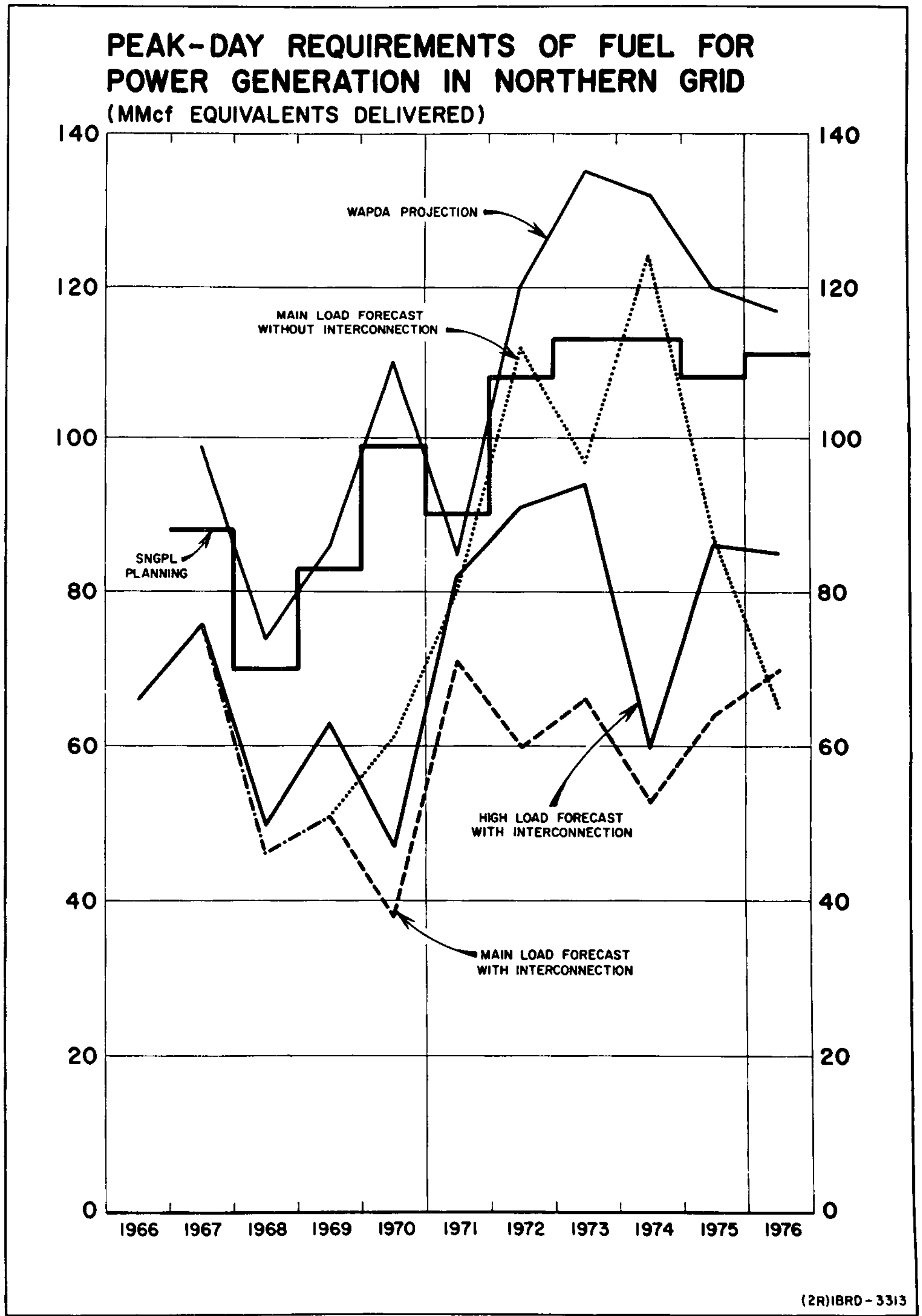

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FIGURE 8.2

The effect of interconnecting the Northern Grid area with Karachi-Sind will, of course, be greatly to worsen the load factor on the thermal plants in the South—and therefore the load factor on the natural gas pipeline which supplies them, assuming that the bulk of their fuel requirements will continue to be provided from Sui. Nevertheless, the load factor on the gas-fired plant in the South will not generally drop below about 40 percent. Analysis of the program including interconnection and concentrated thermal development at Mari indicates that peak-day thermal fuel requirements of the Karachi-Hyderabad area, with interconnection in 1971, would reach a peak in 1970 that would not again be exceeded before the early 1980's; therefore, no additional expansion of the pipeline in the South would be required to meet the needs of the electrical utilities, and in fact the Sui Gas Transmission Company would probably make available to other consumers, as their demands grow, pipeline capacity which became surplus to KESC's requirements. However, there are two reasons why low load-factor demand for thermal fuel will be less costly to Pakistan if it occurs in the South rather than in the North. The first reason is that imported fuel oil can be made available there at considerably less cost than in the North because use in Karachi eliminates the long rail haul. The second reason is that there is a chance the Sari Sing gas field close to Karachi may be suitable for cheap conversion into a gas storage facility, as discussed earlier.

Heavier Draft on Natural Gas Reserves of 'Without Interconnection' Program

Another factor which favors interconnection, but which did not come out fully in the quantitative comparison of the 'with' and 'without' interconnection programs, is the larger amount of thermal fuel, mainly natural gas, that will be required to generate electric power over the next 20 years if interconnection is not undertaken. Heavier consumption of gas arises mainly from two related causes. Firstly, without interconnection, the Karachi-Hyderabad and Upper Sind systems would remain purely thermal. In addition, the fact that the market for hydroelectric power would consequently be confined to the Northern Grid area means that it would not be economically justifiable to bring in the hydro units as quickly as would be the case if a larger market were available to absorb more of their energy immediately it became available. The heavier fuel costs of the 'without interconnection' case did weigh in the comparison of total system costs cited in previous paragraphs. However, the approach to economic fuel pricing is one that makes fuel prices higher over time as more is consumed and less remains for alternative nonelectrical uses. In fact, the economic comparisons between programs with and without interconnection were all made on the basis of the fuel price series developed for the case of Tarbela completed in 1975. The total 1966–85 thermal fuel requirements of the program with Tarbela, interconnection, and 1,100 mw at Mari are actually about 800 trillion Btu's; those of the program with Tarbela but without interconnection are about 1,150 trillion Btu's; and those of the program with Tarbela delayed to 1985 are about 1,400 trillion Btu's. Thus the lack of interconnection does make quite a significant difference to the total amount of thermal fuel required; and recalculation of costs in terms of a more finely tailored set of fuel prices would increase the total present-worth cost of the 'without interconnection' case above the figure used in the quantitative comparisons.

Capacity of Transmission Lines for Carrying Hydro Energy South

The cost calculations of the 'with interconnection' program were based on the assumption that the transmission lines would not be able to carry power in excess of their 'firm capability.' 'Firm capability' was conservatively defined as the capability of a transmission line with one line section being out of service. Thus, for instance, when two single-circuit lines exist between Mari and Lyallpur, their firm capability is taken as the estimated physical capability of one line. This is a correctly conservative approach to the basic analysis of transmission lines, particularly when the transmission line is responsible for bringing firm power to market. In practice, however, use of the maximum physical capability of the transmission lines will probably be worthwhile for carrying to the South hydro energy excess to the requirements of the Northern Grid, though it might involve maintenance of some additional spinning reserve in the South. Therefore analyses have also been made on the basis of the maximum capability of the transmission lines.

Figure 8.3 gives an impression both of the extent to which interconnection increases the capacity to absorb hydro energy into the system and of the difference that is made by assuming higher limits on the carrying capacity of the transmission lines. The figure is based on three runs of the power simulation model—the 'without interconnection' program, the 'with interconnection' program assuming transmission lines could carry power only up to the limit of their firm capability, and the same program assuming transmission lines could carry power up to their 'maximum' capability.[1] The figure indicates the assumptions that were made regarding the years when critical system additions, such as additional transmission lines, would be installed. As pointed out previously, the Tarbela units are phased in much more gradually in the 'without interconnection' program because of the smaller market available for absorption of hydro-energy. Table 8-8 shows the percentage of available hydro energy absorbed in certain key years. The table shows that, despite the slower phasing of the hydro units in the 'without interconnection' case, less of the hydro energy available is generally absorbed in that program than in the other. The table suggests that, if anything, introduction of the hydro units should be postponed to an even greater extent if interconnection is not

[1] See Annex 8-1 for details of specific assumptions regarding carrying capability of transmission lines.

TABLE 8–8
Proportion of Available Hydroenergy Absorbed in With/Without Interconnection Programs

	1975	1980	1985
Without Interconnection Case			
Hydroenergy Available (bln kwh)	9,417	13,377	20,815
Hydroenergy Absorbed (bln kwh)	6,868	10,137	14,723
Absorbed as % of Available	73%	76%	71%
With Interconnection Case (firm transmission capability)			
Hydroenergy Available (bln kwh)	10,215	20,815	20,815
Hydroenergy Absorbed (bln kwh)	8,285	15,525	17,753
Absorbed as % of Available	81%	75%	85%

undertaken. Even with the degree of postponement built into the 'without interconnection' program used here, the amount of hydro energy absorbed in different years is very much less than the amount absorbed if the system is interconnected, as Figure 8.3 makes clear.

The portion of the figure which particularly concerns us here is the difference between the top two lines, one indicating absorption assuming 'firm' transmission capability and the other indicating absorption assuming 'maximum' transmission capability. The differences are very large in the years 1977–79 (raising the possibility that the program might be improved by bringing in an additional line a year or two earlier in order to increase the absorption of hydro power). They are significant in all years after completion of Mangla 7 and 8 (in 1973). In practice, the transmission lines should normally be able to carry hydro energy south to the maximum limit of their physical capability and consequently save fuel there. Some 10-15 percent of the hydro energy would be lost in transmission. In terms of the economic fuel price series based on current estimates of natural gas reserves, fuel savings in the South would have a present worth of about $10 million; at the lower economic fuel price series, corresponding to higher gas reserves, the present worth of the fuel savings would be about $5 million. These should be considered an additional benefit to the 'with interconnection' program, but they should probably have some risk factor attached before inclusion with the benefits discussed previously.

Finally, there are other benefits to interconnecting the power systems of West Pakistan which are of a more general nature and nonquantifiable, but nevertheless significant. Once the various small grids are linked together into a single grid there will be more room for maneuver in system operation, and more flexibility. Unanticipated loads will be more readily assimilable and unexpected delays in completion of new generating plant will cause less disruption as the reserves of other parts of the system are called in to fill the gap or shortages are spread wider and thinner. As the power consultant puts it, "Experience has shown that developments of the nature here proposed (i.e., 380-kv interconnection between power markets) contain additional benefits which usually are not foreseeable at the time the decision to move ahead is made."

THE TIMING OF INTERCONNECTION

With a clear case established for systemwide interconnection in principle, the question arises when it should be initiated. The various programs including interconnection which have been discussed in this Paper all included the first complete link from Lyallpur to Mari to Karachi in 1971. This is somewhat earlier than either Stone & Webster or Harza proposed. Figure 8.3 suggested that interconnection would begin to yield really large benefits in terms of the absorption of additional hydro energy about 1975 when the first units of Tarbela are added to the system. There are of course other important benefits—such as the reduced requirement for fuel in the North and the reduction in needed generating reserves—which would begin to become important earlier. But, if interconnection in general is worthwhile, the choice about timing would seem to revolve around the first five years of the 1970's. Therefore, this problem was set up initially as a choice between 1971 and 1975, and then a number of variants were tested.

Table 8-9 sets out the details of the two main programs prepared for the purpose of establishing the timing of interconnection. The reserve criterion followed in the preparation of these short-term programs was the same as that followed in devising other programs discussed in this report: 12 percent of thermal capability and 5 percent of hydro capability in each market until interconnection and thereafter 12

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FIGURE 8.3

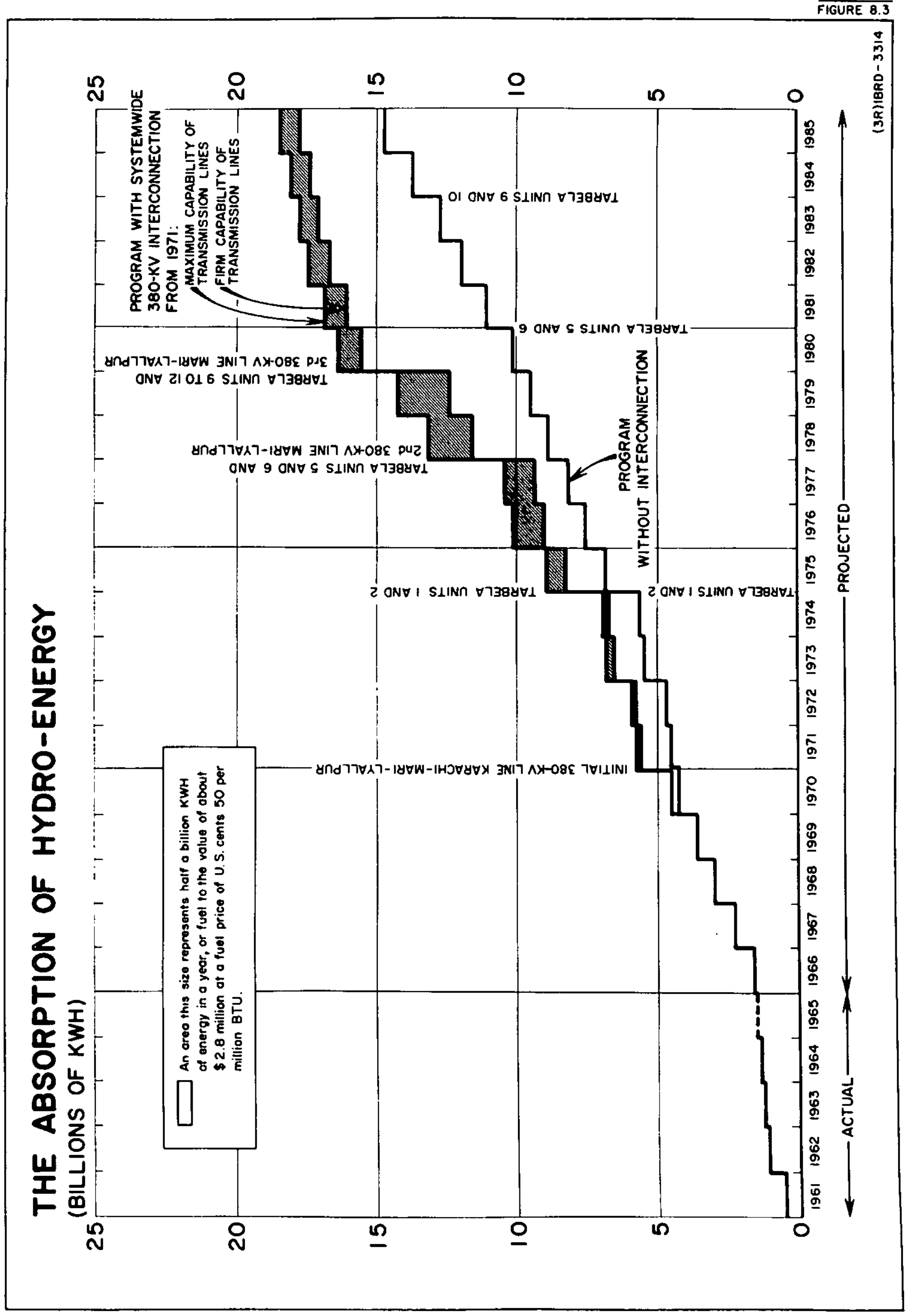

TABLE 8-9
ALTERNATIVE PROGRAMS WITH INTERCONNECTION IN 1971 OR IN 1974/75

	Northern Grid	Upper Sind	Karachi/Hyderabad
		Program A	
1970	Mangla 4, 5, 6	Mari 1 (100)	Hyderabad CT (26)
1971	Retire (15)	Mari 2 (100)	Karachi N 1 (25)
		1st Interconnection with N. & S.	
1972			Karachi N 1 (100)
1973	Mangla 7 & 8		Retire (15)
		2nd Interconnection with S.	
1974		Mari P (200)	
1975	Tarbela 1 & 2		Korangi 4 (125)
1976	Tarbela 3 & 4		
	(1976 critical month—March: system capability—2,541 mw; system peak—2,268 mw)		
		Program B	
1970	Mangla 4	Mari Local (2 × 25)	Hyderabad GT W(26)
	Lyallpur P 1 (100)		
1971	Lyallpur P 2 (100)		Karachi N 1 (25)
	Retire (15)		Korangi 4 (125)
1972	Mangla 5 & 6		Karachi N 1 (100)
1973	Lyallpur P_3 (125)		Retire (15)
1974	Mangla 7 & 8	Mari 1 (100)	
		1st Interconnection with S.	
1975	Tarbela 1 & 2		
		1st Interconnection with N.	
		2nd Interconnection with S.	
1976	Tarbela 3 & 4	Mari 2 (100)	
	(1976 critical month—March: system capability—2,716 mw; system peak—2,268 mw)		

percent of thermal capability and 5 percent of hydro capability on a systemwide basis. There were in addition two other important principles that were followed in constructing these alternative programs: that the Mari and Karachi-Hyderabad areas, when interconnected with the North, should still not have to rely upon the North for firm capability; and that when Karachi-Hyderabad was dependent upon Mari for firm capability there would be at least two EHV transmission lines linking them. In other words, the Karachi-Hyderabad and Mari areas, when interconnected, would always have sufficient installed capability to meet their combined loads though they might draw on the North for reserve capability; and Karachi-Hyderabad would still retain sufficient installed capability to meet its own load without reliance on Mari, except for reserves, until a second Mari-Karachi line had been installed. The Study Group believes that these are properly conservative operational principles for prudent planning.

The result of observing these principles in construction of these alternative programs is (a) the program with postponed interconnection (Program B) ends up in 1976 with about 175 mw more installed capability than the program with early interconnection and (b) the second Mari-Karachi transmission line has to be introduced in this program immediately following the first. The additional capability, which is entirely in the North, would result in the North being self-sufficient for a longer time than would otherwise be the case but it would also be relatively little used since Tarbela and Mangla energy would meet virtually the full Northern Grid load in many months of the year for at least 10 years after completion of the

Tarbela Dam. The existence of the additional capability in the North could lead to some saving from postponement of some of the Tarbela units, but then less energy would be available for sending South. In the quantitative comparisons given below, allowance has been made for the existence of this additional capability in the program with postponed interconnection by means of a credit effective in 1981 for the saving that would then occur as a result of the reduced need for addition of generating equipment; this credit has been subtracted from the total present-worth costs of this case. The second Mari-Karachi transmission line is included in the program with delayed interconnection to enable Karachi to rely on Mari for firm capability and to bring the two programs to the same state of transmission development in the terminal year, 1976. The alternative would be to install more capacity in Karachi, but this would appear to be more expensive because the second transmission line would anyway be needed a year or two later to bring hydro power from the North.

Comparison of the costs of these two programs shows that the program with delayed interconnection (Program B) is more expensive than the program with early interconnection (Program A) at all fuel prices and foreign exchange rates considered, but only slightly more so when fuel is valued in terms of economic prices, which, it will be recalled, were relatively low at this time. Program B is slightly cheaper than Program A in terms of the capital cost of generation and transmission facilities. However, this slight saving is more than outweighed by the additional fuel costs involved in the program with delayed interconnection. The net saving of Program A over Program B is about $10 million when fuel is valued at financial prices. It is harder to define exactly the net saving involved when fuel is valued at economic prices because of the uncertainty discussed as to how the problem of fuel supply for relatively low load factor thermal generation might best be solved. It might be necessary to build pipeline capacity to meet the full peaks; more likely the peaks would be met by fuel oil and no additional pipeline capacity would be required. Alternatively it might prove most economic to construct the pipeline capacity and make it available for serving other gas consumers after the peaks resulting from delay in the EHV interconnection had been met; then a credit has to be allowed as of about 1976 for the existence of the pipeline capacity superfluous to the needs of the thermal plants. Each of these alternatives was tested, and even with the last two solutions, Program B always turned out slightly more expensive in present-worth terms than Program A.

Apart from being somewhat cheaper than the program with delayed interconnection, the program which includes interconnection in 1971 would appear to leave West Pakistan with a technically superior power system by 1975/76. Basically the program with early interconnection ends with a geographical distribution of generating equipment that is much better balanced geographically—that is, in terms of the likely pattern of loads—than the program with delayed interconnection; the lack of geographical balance in the program with delayed interconnection will be further exacerbated as units are added at Tarbela. The heavier thermal development in the Mari area under the program with early interconnection will help to reduce instability problems in the operation of the transmission lines. It will make it easier to adhere subsequently to the present principle of providing sufficient generating capacity in the South (Karachi-Hyderabad and Mari) to meet loads in that area without involving any slowdown in the introduction of units at Tarbela.

Early interconnection will make for the creation of a power system that would be easier to operate.

A number of variants on the two basic programs discussed above were tested but none had lower present-worth costs than the program with early transmission links. One test, for instance, was made of the possibility of postponing each of the two Mari-Karachi links by a year or two and bringing in the 125-mw Korangi Unit 4 in 1971 to keep the Karachi-Hyderabad area self-sufficient for a longer time. With Korangi Unit 4 in 1971 and the Karachi nuclear plant in 1971/72, Karachi would be self-sufficient in reserves as well as basic generating capability through 1973. The first Mari-Karachi line could therefore be introduced as in Program B in 1974, and the second in 1975. Postponement of these transmission lines would make some slight saving in capital costs but this saving would again be more than offset by additional cost of fuel, when fuel is valued at financial prices. If economic fuel prices are used for the two comparisons, there appears little to choose between the two cases. The value of the saving in thermal fuel resulting from the availability of hydro energy in the South is relatively small when calculated in terms of the economic fuel prices considered appropriate at this time and it is of the same order of magnitude as the savings in capital cost resulting from postponement of the transmission lines.

Conclusions

The fundamental conclusion of this discussion is that a power program including 380-kv interconnection between the major power markets, assuming completion of Tarbela by 1975/76 and concentration of thermal development in the vicinity of Mari/Sui, is both economically and technically superior to a power program excluding interconnection; and it also appears that, if the 380-kv system is to be installed, then there are technical and economic advantages to having it earlier rather than later. Nevertheless, these conclusions require some qualification.

In the first place, the analyses described here have all been conducted on the basis of the main load forecast underlying these studies and it is likely that the conclusions drawn from them would be quite sensitive to changes in assumption regarding the growth of loads and their geographical pattern. The direction in which the conclusions might shift as a result of analysis on the basis of different load forecasts is hard to foretell because forces would be at work in both directions—both to strengthen and to weaken the case for interconnection. The greatest uncertainty seems to be that about the load forecast for the Northern Grid, and a higher load forecast was developed for this area as an alternative to the main load forecast. With higher loads in the North, more of the available hydro energy would be absorbed there and less would be available for sending South, so the fuel savings in the South resulting from interconnection would be less significant; these fuel savings were an important factor in the quantitative economic comparison of systems with and without interconnection. However, higher loads in the North could also strengthen the case for interconnection. For instance they might make it worthwhile to bring in the Tarbela units faster and to move on to a further hydroelectric project more rapidly than would otherwise be the case, and since the energy available from any project other than Kunhar is likely to be about as seasonally unbalanced as that from Tarbela and Mangla, the availability of a wider market to absorb more hydro energy in the flood months could be advantageous.

Moreover, to the extent that Northern Grid loads are higher during the early 1970's than assumed in the main load forecasts, the need for a link with Mari will be greater in the pre-Tarbela years.

The second qualification that must be made to the above discussion concerns the date at which initial interconnection should be implemented. The implications of the analysis are that delays beyond 1971 will result in loss of potential savings. This conclusion applies more strongly to the North than to the South because, if Mangla is drawn down to 1040 feet each year and Warsak Units 5 and 6 are postponed until after completion of the first few units at Tarbela, as recommended in Volume One, there will be no alternative to installing additional thermal capacity in the North in order to meet Northern Grid loads in 1971/72 unless the North is interconnected with Mari by that time. As regards the South, the analysis in this Paper showed that the economic case for early interconnection between Mari and Karachi is weaker than the case for early interconnection between Mari and Lyallpur and it is also possible that progress on the Karachi nuclear unit could be speeded up so that it would become reliable more quickly than has been assumed here. Even as regards the North, however, there is somewhat more flexibility than implied in the preceding analysis. In the first place, planning could proceed on the assumption of a higher drawdown level than 1040 feet in some years at Mangla and this could serve to postpone by a year or two the need for further capacity to meet the Northern Grid load. In the second place, there is a possibility of putting in lower voltage lines which could bring some power from Mari to the North and would at the same time be useful in later years for purposes of local transmission. WAPDA apparently plans to extend the existing single-circuit 132-kv line from Rahimyar Khan the additional 40-50 miles required to link the Northern Grid with Mari. This line would be able to carry enough power from Mari to the North to postpone the need for the 380-kv line by one year, according to the analysis of the Power Program in Volume One.

Another reservation which should be borne in mind in relation to these transmission studies is that the conclusions drawn from them do not necessarily apply to 500-kv transmission. As pointed out earlier, most of the transmission studies undertaken were made in terms of 380-kv lines. A 380-kv system would involve considerably lower capital costs in the early years than a 500-kv system. The cost savings of an interconnected system over a noninterconnected system did not appear so great in present-worth terms in this Paper that they would not be seriously reduced by assuming a transmission system with larger capital costs in the early part of the period. A 500-kv system would be able to carry larger quantities of power from the hydro plants and from Mari than a 380-kv system especially in later years, but preliminary studies indicate that, with the economic fuel prices used here and an 8 percent discount rate, the savings in fuel costs would be significantly less in present-worth terms than the extra capital costs involved. Nevertheless, the voltage of a transmission system is a complicated technical matter and the analytical approach adopted here is too simplified for these judgments regarding 500-kv transmission to be more than tentative.

There are other conclusions relating to the construction of gas pipeline capacity which can be drawn from the analysis described in this Paper. The analysis raises doubts about the wisdom of expanding the capacity of the pipeline from Sui to Multan and Lyallpur in order to provide fuel for thermal generation. Figure 8.2, for instance, suggested that, if electrical interconnection is completed in 1971/72 and thermal development is concentrated in the Mari vicinity, then peak-day requirements of thermal fuel for meeting the main load forecast adopted in these studies would not increase above their 1966/67 level before about 1980. The discussion around that figure also suggested that the overall annual load factor on thermal plant in the Northern Grid might be very low over the next 10 to 20 years; moreover, the load would be heavily concentrated in a few months in each year (in the spring), implying that any firm base load on the thermal plants throughout the year would be small. The fact that these analyses were based on a system dispatch assuming availability of hydro capability and hydro energy as of a mean-flow year means that in some years these factors would be less important—and average loads on the thermal plants could be higher—while in years of high flow average loads on the thermal equipment would be somewhat lower. But consideration of these interannual hydrological fluctuations, as well as seasonal fluctuations in the power capabilities of the Mangla and Tarbela units and the resultant low annual load factors on thermal equipment, would only seem to raise further doubts about the validity of expanding pipeline capacity as a means of meeting thermal fuel requirements.

There may be short-term peaks in thermal fuel requirements that will arise in coming years as a result of delays in completion of Mangla units or of interconnection, but the prospect of Tarbela's completion in 1975/76 and the effect that it will have on requirements of thermal fuel in the North seem to recommend against expansion of SNGPL pipeline capacity to meet these peaks—unless it can be done on a purely temporary basis, i.e., if the pipeline can be expanded initially to meet WAPDA's demands and the capacity can subsequently be taken up by other gas consumers. The figures in Table 8-10, which show some of the detail derived from the power system simulation, suggest that it might be wise to consider making available to other consumers some of the pipeline capacity presently committed to WAPDA rather than to expand the pipeline system to meet WAPDA's needs. The central three columns in this table show the average-day and peak-day fuel requirements of the Multan and Lyallpur plants, in the years 1967–77, as derived from the power-system simulation study, assuming power loads of the size projected in the Main Load Forecast underlying these studies. The three columns on the right show the same data for an analysis based on the Higher Load Forecast for the Northern Grid area. And the three columns on the left show figures used by SNGPL in one of their recent planning exercises. The figures derived from the analyses described here, even those based on the higher load projection, are generally lower than those used by SNGPL. It appears that the WAPDA-SNGPL figures fail to show the full impact that Mangla may be expected to make on requirements of gas for electric power generation. The load factors implicit in the projections derived from the power simulation model are generally lower than those implied by the WAPDA-SNGPL figures, especially in the case of the Multan plant. Some of the differences in regard to this plant may arise from WAPDA's assuming that it cannot be operated at low loads. However, Stone & Webster assert in their report that, despite the close clearances of the older two turbines at Multan, they probably can be run for peaking purposes with careful operation and that the operators should therefore be trained accordingly. The figures based on the computer studies also contrast with the WAPDA-SNGPL figures in that they always

TABLE 8-10
PROJECTIONS OF GAS REQUIREMENTS OF WAPDA NORTHERN GRID PLANTS

	WAPDA-SNGPL			Study Group: Main Load Forecast			Study Group: High Load Forecast		
	Average Day MMcf	Peak Day MMcf	Load Factor (%)	Average Day MMcf	Peak Day MMcf	Load Factor (%)	Average Day MMcf	Peak Day MMcf	Load Factor (%)
				Multan Steam Plant					
1967	44	70	63	10	38	26	13	42	31
1968	31	52	60	5	19	26	6	22	27
1969	41	56	73	4	24	17	7	32	22
1970	35	65	54	1	14	7	3	22	14
1971	23	62	37	7	36	19	12	39	31
1972	31	72	43	6	28	21	14	40	35
1973	37	77	48	5	34	15	16	42	38
1974	48	77	62	4	26	15	10	30	33
1975	27	74	36	5	33	15	11	39	28
1976	24	77	31	4	36	11	11	41	27
1977	41	77	53	4	34	12	8	39	21
				Lyallpur Steam Plant					
1967	13	18	72	16	38	42	18	37	49
1968	12	17	71	12	29	41	14	29	48
1969	18	82	42	9	29	31	13	21	42
1970	21	33	64	3	26	12	5	27	19
1971	11	18	61	9	31	29	13	29	45
1972	13	33	39	9	36	25	13	35	37
1973	20	36	56	7	29	24	14	36	39
1974	17	36	47	7	24	29	11	21	52
1975	7	34	21	6	27	22	14	32	44
1976	6	34	18	4	32	13	13	29	45
1977	11	34	32	4	30	13	9	31	29

indicate a higher load factor on the Lyallpur plant than on the Multan units owing to the somewhat greater thermal efficiency that the Lyallpur units should have. Besides the differences in load factors, the peak-day requirements of fuel for the Multan units as derived from the computer analysis are generally below the peak-day requirements indicated by the WAPDA-SNGPL projections; those for the two plants combined are also generally below the WAPDA-SNGPL figures, although Lyallpur peaks are sometimes higher.

As regards the Southern gas pipeline system, it was pointed out earlier that one of the savings accruing to the power system from interconnecting the North and South would be elimination of the need for expansion of the Sui-Karachi pipeline to meet fuel requirements for power generation between 1970 and 1980. Figure 8.1 indicated that peak-day requirements of natural gas for power generation may rise between 1966 and 1970 from about 40 MMcf/day to about 75 MMcf/day. They will subsequently fall as a result of introduction of the Karachi nuclear plant in 1971/72 and completion of interconnection in 1971/72. With interconnection in that year there will be no peaks above about 80-90 MMcf/day before the late 1970's or early 1980's. Thus some expansion of the SGTC pipeline may be needed in the years up to 1970/71 to meet the needs of KESC and the WAPDA plants in Hyderabad. However, since KESC's demands will have a much lower annual load factor after interconnection than they do now, it may become economical for KESC to buy a larger portion of its fuel in the form of fuel oil and for SGTC to make available to other consumers the pipeline capacity thereby freed.

Transmission Data

From the point of view of long-term planning, the most critical questions concerning transmission are whether EHV should be introduced and when. Both S&W and Harza, in developing their recommendations that EHV be initiated in the early 1970's, based their studies heavily on the assumption that there was available at Mari a large reserve of low-quality gas without much alternative use. The Study Group's view that important alternative uses for this gas exist—particularly for production of fertilizers—was reinforced when in the middle of 1966 the estimate of gas reserves at Mari was also substantially reduced. Thus, the Study Group embarked on its reappraisal of EHV interconnection between the major power markets of West Pakistan. Interconnection also had to be considered in its relation to the phasing of the addition of generating units at Mangla and Tarbela and in relation to the chief alternative means of energy transmission available in the Province—gas pipelines.

For purposes of studying these problems, it seemed appropriate to use a simplified approach based on the power consultant's figures and assumptions, which are not inconsistent with those of Harza. The alternative (380 kv and 500 kv) EHV transmission programs drawn up by the power consultant were broken into fragments, the parts of which could be scheduled at different times. Annex Table A8-1 indicates the costs and firm capacities of the various stages of 380-kv interconnection between Lyallpur and Mari and between Mari and Karachi, each stage corresponding to the addition of a further line. The capacity estimates are approximations whose validity depends on a number of technical assumptions. The key assumption is that any one line could be out of service at any time. When there is only one line in existence as in the early years, the carrying capacity of the line has been taken arbitrarily as half the capacity of one line.

However, as stated in main discussions, this may be a too-conservative criterion where each market has sufficient generating capability to meet its own load independently and the transmission line is used primarily to bring in cheaper (e.g. hydro or Mari-generated) energy. In some programs, and in some years, the transmission lines would be providing firm capability; but in others they would not. Therefore, some studies were made, with the capacity of the lines taken as the maximum that they could physically carry, given their voltage and their length. Annex Table A8-2 shows the figures adopted for maximum transmission capability and compares them with the firm capacities.

Annex Table A8-3 indicates the costs of a 500-kv system and its major components. The comparable firm and maximum carrying capacities of a 500-kv system at various stages of its development are shown in Annex Table A8-4.

The costs of transmission included in Annex Tables A8-1 and A8-3 above cover the lines themselves, related terminals and shunt reactors. There are other costs,

ANNEX TABLE A8-1
380-KV EHV LINES: COSTS AS USED IN COMPUTER PROGRAM
($ million)

		Domestic						Foreign						Total Domestic and Foreign
	Year:	−3	−2	−1	0	1	Total	−3	−2	−1	0	1	Total	
Link 1 and 3, Lyallpur-Mari														
Stage 1, 170 mw Southwards														
Line			1.2	4.3	1.2		6.7		1.5	5.2	1.8		8.5	15.2
Terminals				0.2			0.2			0.8			0.8	1.0
Shunt Reactors				0.2			0.2			0.6			0.6	0.8
			1.2	4.7	1.2		7.1		1.5	6.6	1.8		9.9	17.0
Stage 2, 340 mw Southwards														
Line			1.2	4.3	1.2		6.7		1.5	5.2	1.8		8.5	15.2
Terminals				0.4			0.4			1.5			1.5	9.9
Shunt Reactors				0.2			0.2			0.6			0.6	0.8
			1.2	4.9	1.2		7.3		1.5	7.3	1.8		10.6	17.9
Stage 3, 680 mw Southwards														
Line			1.2	4.3	1.2		6.7		1.5	5.2	1.8		8.5	15.2
Terminals				0.4			0.4			1.5			1.5	1.9
Shunt Reactors				0.2			0.2			0.6			0.6	0.8
			1.2	4.9	1.2		7.3		1.5	7.3	1.8		10.6	17.9
Link 2, Mari-Karachi														
Stage 1, 250 mw to Karachi														
Line			1.4	4.6	0.9		6.9		1.8	5.7	1.2		8.7	15.6
Terminals				0.4			0.4			1.5			1.5	1.9
Shunt Reactors				0.6			0.6			1.8			1.8	2.4
			1.4	5.6	0.9		7.9		1.8	9.0	1.2		12.0	19.9
Stage 2, 800 mw to Karachi														
Line			0.9	2.7	0.9		4.5		1.2	3.2	1.2		5.6	10.1
Terminals				0.8			0.8			3.1			3.1	3.9
Shunt Reactors				0.1			0.1			0.5			0.5	0.6
			[illegible]	[illegible]	[illegible]		[illegible]		[illegible]	[illegible]	[illegible]		[illegible]	[illegible]

the most important of which are the step-up transformers at the generators and step-downs from the EHV lines. The size and costs of these will vary not only with the transmission system installed but also with the generating plant installed. Costs of step-ups and step-downs at market for the Tarbela, Mangla and Kunhar units were therefore included, along with the cost of transmission to market (380 kv for Tarbela and 220 kv for Mangla and Kunhar), in the investment costs of the units themselves. Costs of step-ups required for thermal stations and the step-downs required for bringing the energy down again to local voltage at markets were added as a special terminal correction to the discounted present-worth costs of alternative systems when interconnection was in question.

ANNEX TABLE A8–2
CARRYING CAPABILITY OF 380-KV LINE
(mw)

	Firm		Maximum	
	Southwards	Northwards	Southwards	Northwards
Mari-Lyallpur, Stage 1	170	250	340	500
Stage 2	340	550	680	1,100
Stage 3	680	1,100	1,100	1,600
Mari-Karachi, Stage 1	250	—	500	—
Stage 2	800	—	1,500	—

ANNEX TABLE A8-3
500 KV EHV TRANSMISSION: COSTS AS USED IN COMPUTER PROGRAM
($ million)

	Domestic							Foreign							Total Domestic and Foreign
Year:	−4	−3	−2	−1	0	1	Total	−4	−3	−2	−1	0	1	Total	
Link 1 and 3, Lyallpur-Mari															
Stage 1, 320 mw Southwards			1.7	6.3	1.7		9.7			2.5	9.0	2.5		14.0	23.7
Terminals				0.3			0.3				1.0			1.0	1.3
Shunt Reactors				0.3			0.3				1.2			1.2	1.5
			1.7	6.9	1.7		10.3			2.5	11.2	2.5		16.2	26.5
Stage 2, 630 mw Southwards			1.7	6.3	1.7		9.7			2.5	9.0	2.5		14.0	23.7
Terminals				0.2			0.2				1.0			1.0	1.2
Shunt Reactors				0.3			0.3				1.2			1.2	1.5
			1.7	6.8	1.7		10.2			2.5	11.2	2.5		16.2	26.4
Line 2, Mari-Karachi															
Stage 1, 750 mw Southwards			2.3	6.0	1.3		9.6			3.1	8.6	1.9		13.6	23.2
Terminals				0.5			0.5				2.0			2.0	2.5
Shunt Reactors				0.8			0.8				2.4			2.4	3.2
			2.3	7.3	1.3		10.9			3.1	13.0	1.9		18.0	28.9
Stage 2, 1,500 mw Southwards			1.4	3.4	1.4		6.2			2.0	5.0	2.0		9.0	15.2
Terminals				0.5			0.5				2.1			2.1	2.6
Moro Substation				0.7			0.7				3.0			3.0	3.7
Shunt Reactors				0.2			0.2				0.8			0.8	1.0
			1.4	4.8	1.4		7.6			2.0	10.9	2.0		14.9	22.5

ANNEX TABLE A8–4
CARRYING CAPABILITY OF 500-KV LINE
(mw)

	Firm		Maximum	
	Southwards	Northwards	Southwards	Northwards
Mari-Lyallpur, Stage 1	320	630	630	1,200
Stage 2	630	1,200	1,200	2,400
Mari-Karachi, Stage 1	750	—	1,500	—
Stage 2	1,500	—	3,000	—

The Calculation of Annual Gas Requirements and Peak-Day Gas Requirements

As will be shown in Supplemental Paper No. 9, the results of the Study Group's simulation analysis took the form of computer printouts—a system operation summary of each of the two markets—Northern Grid and South (Hyderabad-Karachi)—for each of the 20 years of the planning period. These system operation summaries show how the system could, according to the simulation program, be optimally operated if economic conditions were those indicated by the 'financial' set of fuel prices (i.e. approximately the current structure of prices in different parts of the Province) and the current foreign exchange rate. At the other combinations of fuel prices and shadow exchange rates used for studies of gas consumption, interconnection, etc. the picture would not in fact look very different from the one printed out.

These system operation summaries give monthly plant factors for each of the thermal plants on the system, for they are the outcome of the computer's dispatching operation. The plant factors show the average load on the plant during that month as a percentage of its net capability. By summing these plant factors over a year, it is possible to get an indication of total gas requirements;[1] and by considering the figures for the month in which peak use is made of thermal capacity, it is possible to get an indication of peak-day gas requirements. The procedures for deriving these estimates from the plant factors printed out are described in the following paragraphs.

Annual Gas Requirements

The sum of the monthly plant factors for each plant in each year gives the computer's estimate of the extent this plant would be required if the system were optimally dispatched. It would be possible to multiply this figure by the amount of gas that the plant in question requires to run at its full net capability 24 hours a day each day of the month (the "gas factor" in Table A8-1) in order to derive total gas requirements. However, this would result in an underestimate of total gas requirements for a variety of reasons. In the first place, the amount of energy available from the hydro units in the mean year has been exaggerated in this study by about 2 percent by taking it gross (instead of net) of generation losses and auxiliary uses. Hydro supplies account for 50–66 percent of systemwide requirements over the

[1] The plant factors for the plants located in the Northern Grid area and Karachi-Hyderabad may be handled directly in this way. Mari plants, on the other hand, are dispatched both to the North and to the South, and so their plant factors are derived by multiplying the plant factor for the plant in question for that month as given in the printout for the Northern Grid by the "share of Mari" figure given a few lines below, then performing the same operation for the South, and adding the two together. It should be recalled also that this represents only the plant factor incurred by the Mari plants in generating energy for "export" to Karachi and the North. Gas required for local generation must be calculated separately.

planning period, so the estimates of gas consumption should be raised a few percentage points on this account. There are also four other factors which would tend to raise annual gas requirements above those derived from direct application of the plant factor figures given in the computer printout. First, the computer model assumes optimal operation of the system, whereas coordination of such a complex system may prove extremely difficult and performance may not always reach the degree of optimality assumed by the computer. The computer program assumes that all thermal plants can be operated at any load factor, which may in fact prove physically difficult.[1] The difficulty of operating the Multan units at a low load factor has apparently led to their being run at close to full load while water was being spilled at Warsak. Secondly, the computer model fails to make allowance for the fact that heat-rates tend to deteriorate seriously at low load factor operation. If the plants were in fact operated at the high point in the load curve implied by their low plant factor, i.e. for peaking purposes, this would clearly cause gas requirements to be somewhat higher than implied by calculations based on an average heat rate. However, the heat rates used in these studies are somewhat worse than the optimal ones, making some allowance for departure from a high load factor. Moreover, more precise optimization of dispatching might show that there was sufficient peaking capability available on the hydro units, or on more efficient thermal plants, to give some thermal plants used for peaking in the computer study a low but steady base load position: the lack of fluctuations in load would bring their overall fuel efficiency back to the average position used in the computer studies (or better). Thus it is uncertain whether the gas consumption has in fact been underestimated on these grounds, but it may have been. Thirdly, the computer model makes no allowance for maintenance, fully loading the most efficient units, when needed, throughout the year. This would not significantly affect the Northern Grid where there are long periods in most programs when the thermal plants are virtually out of service, but it would have an effect in the South, meaning that somewhat less efficient units would have to be brought on during short periods when the most efficient were out for maintenance. This could raise the average systemwide fuel consumption somewhat but its overall importance is probably extremely small. Fourthly, the computer program makes no allowance for the maintenance of spinning reserve and the generation of reactive power, needs for which will become increasingly important as the long transmission lines are installed and the widely spread-out system is integrated. These two factors together might increase fuel requirements by 2–3 percent.

The total effect of these various factors would appear to require increasing the estimates of gas requirements derived directly from multiplying plant factors by "gas factors" by about 10 percent. The calculations shown in the main text are made on the basis of gas factors increased by 10 percent.

[1] This may be the case, for instance, with the two 62-mw units at Multan installed in 1960. Some say that they cannot be operated at low plant factors. However, the power consultant comments in this regard: "The turbines . . . have close clearances with the result that more than ordinary care must be used when starting and stopping the units, and the automatic controls only function from full to about one-quarter load. The operators consider they should be used for base-load purposes; however, after Mangla hydro units come into service, these units will be needed for peak load purposes and the operators will have to be trained to give the units the extra attention necessary." Stone & Webster, A Program for the Development of Power in West Pakistan, Volume Two (May 1966), Annex C, p. 4.

Peak-Day Gas Requirements

The capacity of the gas pipelines in West Pakistan is generally considered in terms of the maximum amount of gas that could be put through the line in one day. On SGTC's line between Sui and Karachi-Hyderabad, for instance, the peak-day capacity is about 110 MMcf/day (following completion of the compressor station at Nawabshah). Deliveries over a two-three hour period can be increased above the 4.6 MMcf/hour (110/24) rate that this would imply to about five MMcf/hour or a rate of 120 MMcf/day by means of packing gas in the pipeline. This may be done to meet the high peak, which presently occurs between 6 and 8 a.m. or to meet the rather low evening peak, but it does not alter the maximum capacity of the line under present capacity and current load pattern of 110 MMcf/day.

To gain an impression of the increase in gas pipeline capacity that would be needed by our alternative power development programs we need therefore to express gas requirements in terms of peak-day needs. From the computer printout it is possible to derive peak-month gas requirements. These have been obtained by multiplying the peak-month plant factor of each plant by its gas factor, as given in Annex Table A8-5. For the purpose of assessing peak-day requirements no adjustment has been made such as discussed above to make allowance for maintenance, spinning reserve, reactive power, etc., since it was desired to stay on the conservative side in the estimation of gas pipeline capacity; small peaks can always be met by use of fuel oil or, as seen above, by packing in the pipeline or, possibly though more expensively, by provision of conventional underground storage or storage tanks.

The next step is to derive peak-day requirements from average-day requirements during the peak month. The relationship between KESC's peak-day gas requirements and their average daily requirements in the peak month now appears to be about 1.1:1. The relationship[1] between total electric energy produced on the peak day and that produced on the average day of the peak month is 1.12:1. That this ratio should be slightly higher is to be expected, since KESC meets a portion of its peak fuel requirements with liquid fuel. If all fuel were to be supplied by gas, then the relationship between peak-day gas requirements and average day gas requirements in the peak month would presumably also be about 1.12:1.

It would be false, however, to project these relationships into the future, for they belong to a system fueled almost entirely by natural gas. They could change if gas-fired generation were pushed lower on the load curve by substituting more fuel oil at the peak; the load factor on the pipeline would then further improve. And they could change substantially in the opposite direction if local gas-fired generation were pushed up the load curve by substituting nuclear energy, units fired by cheaper gas (i.e., Mari) or hydro energy at the bottom of the load curve. The computer studies show, as might be expected, that the latter is the case. These studies may somewhat exaggerate the extent to which optimization of dispatching will require the main gas-fired units in the North and the South to be pushed to the top of the load curve, for, as pointed out in the foregoing discussion of annual gas requirements, there may in some years be sufficient hydro or cheaper thermal

[1] Cf., for example, Kuljian Corporation, "Report for Water & Power Development Authority West Pakistan on Phase No. 1 Mari Thermal Power Project two-66,000 kw Units" (May 1965) Section 3, Table 32.

ANNEX TABLE A8-5
GAS FACTORS FOR SELECTED PLANTS

$$\text{Gas Factor} = \frac{\text{Capability} \times \text{Heat Rate} \times 730}{\text{Btu rating of gas}}$$

where 730 is average number hours in a month and Btu ratings are assumed as follows: Sui 975 Btu/cuft Mari 725 Btu/cuft Heat Rate is defined in Btu per net Kwh set out.

Plant	Capability (mw)	Heat Rate (Btu/net kwh)	Factor (MMcf)
Multan S1	124	11,800	1,095
Multan GT	6	14,000	63
Lahore GT 1	26	18,000	350
Lyallpur S1	124	11,500	1,068
Lyallpur 1	100	11,500	861
Lyallpur P	100	17,500	1,310
Lyallpur 5	150	11,300	1,269
Lyallpur 6	200	10,700	1,602
Lyallpur 8	300	10,400	2,336
Mari 1	100	12,000	1,208
Mari P	200	18,000	3,625
Sukkur	50	13,000	487
Karachi A	15	24,000	270
Karachi B	25	18,000	337
Karachi Bx	60	12,700	569
Karachi DF	15	11,400(80%)	102
Karachi K1	66	11,300	558
Karachi K2	66	11,300	558
Hyderabad S_1	22	16,000	263
Hyderabad S_2	15	13,000	145
Hyderabad GT	6	24,000	108
Kotri GT	40	18,000	539
Hyderabad GT_2	26	17,500	340
Korangi 3	125	11,300	1,057
Korangi 5	200	10,700	1,601
Korangi 7	300	10,000	2,244

capability and sufficient transmission capacity to peak with these and give the local thermal units a lower position on the load curve, where they will be less subject to deteriorating fuel efficiency. A brief inspection of the printouts raises doubts as to whether this will in fact be the case since the controlling peak gas requirements in fact generally arise in March or May in the North and in the same months in the South when the system is interconnected and it is in those months precisely that the system is very short of capacity and making full use of whatever is available at the hydro plants, Mari and the nuclear plants.[1] Nevertheless, there may indeed be opportunities, in practice, for running the system in a manner which would maintain a better heat rate at less efficient plants. As far as our estimates of peak-day gas requirements are concerned, the potential savings from such improved operation may well be counterbalanced by the failure to allow for any deterioration in

[1] The only exception to this seems to be in some years in the South with an interconnected system; for then the peak-gas requirements sometimes occur in December when there is often considerable spare hydro capability (though not energy) and also spare transmission line capacity. If there is indeed opportunity under these circumstances for swapping hydro and local thermal usefully on the load curve, then this would tend to reduce peak day gas requirements in the "with interconnection" cases and strengthen the argument in favor of it.

heat rate resulting from low load factor operation which will anyway be necessary on some plants. Therefore the procedure adopted estimates peak-day gas requirements without allowance for the uncertain possibility of savings from this source.

The essential problem in defining the trend of the relationship between peak-day gas requirements in the peak month and average-day gas requirements in the peak month is the extent to which gas-fired generation will be pushed into the top part of the load curve, so that the base from which demand for gas is fluctuating is smaller than it would be in an entirely gas-fired system. The best approach to defining this tendency appears to be an analysis of the total energy requirements as supplied from different sources. Thus it is possible to define the gas base (or average-day gas requirements) as equivalent to the amount of energy which is supplied from local gas-fired plants; then, if it is assumed that the relationship between peak-day electrical energy requirements and average-day electrical energy requirements in the peak month will remain constant and, if it is also assumed that peaks will be met by means of gas it is possible to estimate peak-day gas requirements from average-day gas requirements in the peak month.

A simple formula was used for calculating the peak factor by which average-day gas requirements during the peak month were multiplied in order to derive peak-day gas requirements on the assumption that major power peaks would be met with gas. The formula in effect provides a summary of this discussion:

$$\text{Peak Factor} = \frac{1.12 \times E_{pkm} - (E_n + E_m + E_h)}{E_{pkm} - (E_n + E_m + E_h)}$$

where E_{pkm} = Average day electrical energy requirements in peak month

E_n = Average day supply of nuclear energy in peak month

E_m = Average day supply of electrical energy from Mari in peak month

E_h = Average day supply of hydro energy in peak month

The values of the elements in this formula can be deduced quite readily for both the Northern Grid and the Karachi-Hyderabad area from the computer printout; the peak factors for the North and for the South can then be derived for the peak month in each year of the planning period for each alternative power program.

The higher the proportion of total energy requirements supplied by nuclear, hydro, or Mari capability, the higher will be the peak factor. Annex Table A8-6 indicates the values of the peak factor for the three main programs studied in connection with EHV transmission. In the North, the values range between about 120 and 220 for the program without interconnection. They are substantially higher in the program with interconnection because then the hydro units are brought in more quickly and there is greater reliance on cheap supplies of power from Mari. In the South, the values range between about 112 and 120 for the program without interconnection until the early 1980's when they rise as a result of the installation of nuclear units. Again, they go substantially higher in the programs with interconnection because of the availability of hydro energy from the North and greater use of Mari energy.

ANNEX TABLE A8-6
PEAK FACTORS[a]

	North			South		
	Without Inter-connection	With Inter-connection and 400 mw Mari	With Inter-connection and 1,100 mw Mari	Without Inter-connection	With Inter-connection and 400 mw Mari	With Inter-connection and 1,100 mw Mari
1966	126	126	126	112	112	112
1967	118	118	118	112	112	112
1968	143	143	143	112	112	112
1969	147	147	147	112	112	112
1970	145	198	198	112	112	112
1971	134	140	140	113	121	121
1972	129	156	151	118	119	119
1973	139	155	160	117	129	118
1974	133	188	188	116	124	124
1975	156	182	182	115	130	130
1976	225	211	211	115	126	165
1977	193	229	229	114	124	207
1978	217	233	233	114	122	192
1979	189	282	282	114	126	195
1980	170	337	337	118	124	168
1981	210	235	390	134	130	154
1982	221	257	444	130	144	143
1983	188	186	526	157	140	190
1984	212	194	207	146	168	166
1985	210	162	258	139	142	166

[a] As defined in text.

Unit Costs of Investment in Gas Pipeline Expansion

The following unit costs, which are supposed to be economic costs (i.e., excluding taxes, duties and interest during construction) at 1965 prices were obtained from reports kindly made available by SGTC and SNGPL.[1]

Capital Costs	Cost ($ million)		
Looping	Foreign Exchange	Domestic	Total
16-inch Loop, per 100 miles	3.6	2.7	6.3
18-inch Loop, per 100 miles	4.7	3.5	8.2
Compressors			
2 × 1,100 BHP Units	0.65	0.35	1.0
1 × 1,100 BHP Additional Unit	0.21	0.17	0.38
2 × 1,500 BHP Units	1.50	1.50	3.0
1 × 1,500 BHP Unit	1.00	1.20	2.2
1 × 1,500 BHP Additional Unit	0.60	0.20	0.8

Operating Costs ($)		
Loops: $630/mile p.a. compressors (p.a.):	1,100 BHP Solar Units	1,500 BHP Reciprocating Units
Labor and Overheads	21,000	42,000
Spares and Lube	9,240	12,600
Fuel	24,370	21,000
Total	54,610	75,600

[1] Mainly:
(1) SGTC: SGTC Expansion—Technical and Financial Study prepared in London by the Burmah Oil Company (Pakistan Trading) Ltd., for the Sui Gas Transmission Company Ltd., Karachi, (May, 1966).
(2) SNGPL: Appraisal No. 3 of Cost and Viability for Pipeline Extensions to Daudkhel and Peshawar (October, 1966).

SUPPLEMENTAL PAPER IX

The Power System Simulation Model

This Paper attempts to describe the manner in which the simulation model is used in system planning and also to give a clear and complete presentation of the basic principles of the model. The general order of procedure is, first to discuss in a general way the preparation of alternative system plans and the use of the simulation model for comparing them. Second, the heart of the Paper discusses in some detail the main principles governing the system dispatch performed by the model. Third, later sections give details of the data requirements for the computer program and describe the computer printout. While this paper provides an overview of all main aspects of the simulation model and its use, it does not attempt to show all the supporting derivations or any complete sets of equations.

The Study Group was most fortunate in securing the services of Dr. Henry D. Jacoby, a member of the Department of Economics of Harvard University, to help with these problems. Dr. Jacoby had developed a computer simulation model for use in planning the expansion of electric power systems[1] and, for purposes of the Study Group's work, he elaborated the model extensively to take account of many of the specific characteristics of the West Pakistan power systems. The result is a computer program which simulates both the short-run operation and the long-run expansion of what is likely to become the interconnected power grid of the Province. A glossary of the symbols used in this paper is attached at the end.

Load Forecasts and Alternative System Expansion Plans

Like most approaches to electric power system planning, the simulation technique operates on the basis of a deterministic projection of market capacity and energy demand. System load is exogenous to the model. In effect, it is assumed that investment to serve projected demand is always justified; the willingness of consumers to pay for electric power is assumed to be greater than the cost of supply within the relevant range of equipment and fuel costs. From the standpoint of the planning model, therefore, the load forecast is a set of constraints; all valid investment plans must provide sufficient generation and transmission capacity to serve the growing markets.

Within the model, West Pakistan is treated as consisting of three major power markets: (1) the Northern Grid, with its large sources of supply and demand, (2) a Southern Market composed of Karachi and Hyderabad, also with existing and potential load and generating facilities, and (3) the Upper Sind (Mari-Sukkur

[1] See H. D. Jacoby, "Analysis of Investment in Electric Power," Harvard University Center for International Affairs, Economic Development Report No. 62 (mimeo, 1967).

area), with its potential development of thermal generation and its demand. The small Quetta system has little bearing on the questions under study, and it was not included in the analysis.

Load forecasts were prepared for each of the three markets. Alternative system expansion plans were defined as being "equivalent" in the sense that each would meet all the forecasted loads with an acceptable standard of service. A simple criterion was adopted for equivalent quality of service: total generating capacity available in any month must exceed peak load in that month by a reserve margin equal to 5 percent of hydroelectric capacity available[1] plus 12 percent of thermal capacity installed.

The analysis can be extended by making alternative assumptions about future load growth or reserve requirements. Analyzing their implications would involve definition of a different set of alternative power programs and separate runs of the computer model. In the Study Group's work, such runs were made only for alternative load forecasts.

The expansion plans considered relates only to generating plant and long-distance intermarket transmission; intramarket distribution networks are not considered. For purposes of the Study, generation is considered to end at the point power enters the market distribution grid. If a plant is located within the geographical confines of a market, the generation stage stops at the high voltage or market side of the main generator transformer. If, on the other hand, a plant is located far from the market, then the analysis may be extended to include the operation of the transmission line, or the plant itself may be defined to include transmission to the point of entry into the grid. This normally will be at the low voltage side of the step-down transformer at the market end of the transmission line. Analysis of the transmission of power between two distant markets requires that explicit consideration be given to the limits and losses associated with a long-distance transmission system.

Several important assumptions should be noted. In working with the sub-optimization of investments in generating capacity and intermarket transmission, the existence within each market of a fully integrated grid system is implicitly assumed. Further, it is assumed that no market is so large geographically as to involve significant differences in distribution losses within the system; in effect, it is assumed that power can be transmitted from any location in the grid to any other at any time at equal cost.

This equal cost assumption need not always hold true in reality. Distribution costs often influence the allocation of production among plants and may affect the location of new generating stations in relation to centers of load concentration and fuel supplies. Furthermore, it is quite possible that the load demand in some parts of a market may go unserved while generating capacity lies in other parts because distribution lines may be operating at maximum capacity. It is not often the case, however, that the characteristics of the intramarket distribution system affect the selection of investments in generation or long-distance transmission, and this does not appear to be a problem in West Pakistan.

To describe how equivalent alternative expansion plans are defined under a particular load forecast, it is convenient to begin with the case of a single isolated

[1] Hydroelectric capacity taken for this purpose as the lowest in the course of the month, under critical-year hydrological conditions.

market. Let the subscript i serve as an annual time index, $i = 1, \ldots, N$, where N is the last year of the planning period—year 20 for purposes of this study, or 1985. And let the subscript T be used as a monthly time index, $T = 1, \ldots, 12$.

Suppose there is a number of generating units, U_j, $j = 1, \ldots, J$, which might be in service during some particular year where $j = 1, \ldots, \textit{j}$, are existing and potential thermal and nuclear units and $j = \textit{j} + 1, \ldots, J$ are the hydro possibilities. Each thermal or nuclear unit is characterized by its rated output capacity net of in-station losses and consumption, Q_j, assumed constant over any year. The output characteristics of each hydro plant are represented by its capacity, Q_{jT}, and the associated energy, H_{jT}, in each month of the planning period.

For each generating unit U_j there is a scale variable, x_{ji}, which is appropriate for each year. The variable x_{ji} is limited to the values zero and one. If a particular U_j is on the system in a particular year, $x_{ji} = 1$; if not, $x_{ji} = 0$. During any year, the system supply structure will be composed of some subset of U_j. Additions to and deletions from system generating capacity are planned under a set of 12 N constraints of the following form:

$$O \leqslant \delta_T = \sum_{j+1}^{j} \frac{Q_j x_{ji}}{1 + r_1} + \sum_{j=\textit{j}+1}^{T} \frac{Q_{jT} x_{ji}}{1 + r_2} - P_{maxT} \qquad \text{(Equation 1)}$$

The terms r_1 and r_2 relate to the reserve generating capacity requirements for thermal capacity and hydroelectric capacity, respectively. In these studies r_1 was assigned the value 0.12 and r_2 was set at 0.05, as stated above. The term P_{maxT} is the maximum capacity demand in month T, and δ_T indicates the excess reserve on the system during the period and must always be nonnegative.

Power development programs which meet the capacity constraints of Equation 1 in each month of the planning period are defined as equivalent alternatives insofar as they can all meet system demand with a satisfactory level of service quality. Such a power development program is termed a "strategy" in the terminology of this simulation approach, and each strategy may be denoted by a matrix of zeros and ones, $X = \| \chi_{ji} \|$; $j = 1, \ldots, J$; $i = 1, \ldots N$. The particular combination of plants in existence in any year, i, is indicated by the appropriate column vector, $\chi_i = [\chi_{1i}, \ldots, \chi_{Ji}]$.

A strategy is introduced into the computer analysis in the form of two vectors which indicate the dates during the planning period when each of the planned system additions or retirements is to be made. S_j is a "start" vector; it applies to that subset of U_j composed of potential projects, those for which $x_{j0} = 0$. A potential project may be introduced at any time during the planning period; that is to say, $1 \leqslant S_j \leqslant N$. R_j is a "retire" or "stop" vector, and it applies to that subset of U_j which is in existence at the beginning of the planning period, i.e., $x_{j0} = 1$. Since an existing project may be retired at any time during the planning period, $1 \leqslant R_j \leqslant N$.

EHV Interconnection of Markets

The computer program considers the dispatching of generating units in both the Northern and Southern markets (Markets No. 1 & 2), the potential development of generation units in the Upper Sind (Market No. 3), and the possible transmission of power between these various locations. Any particular month may find the markets in one of four configurations with respect to interconnection as indicated in Figure 9-1:

A. No interconnection at all.
B. Connection from Mari to the South only.
C. Connection from Mari to the North only.
D. Connection of North with South via Mari.

The computer program must be able to handle all of these; all strategies start in Condition A and most proceed to Condition B or C and then to Condition D in the

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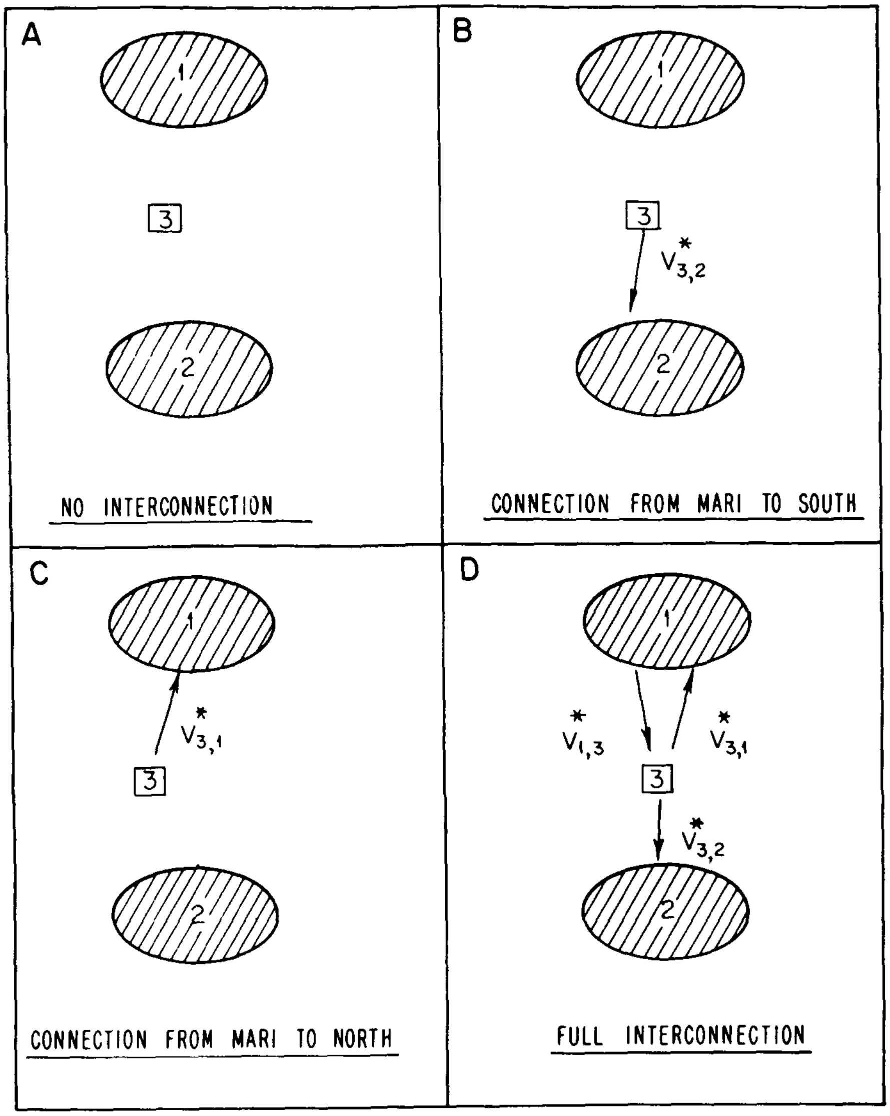
FIGURE 9.1



CONFIGURATIONS OF SYSTEM TRANSMISSION

course of the planning period. Each transmission line is denoted by the numbers of the markets of origin and destination of the power sent over it. Thus, for example, the connection from Mari to the South is denoted Link 3,2. The transmission capacity of the line is denoted as $V^*_{3,2}$, as indicated in Box B of Figure 9-1.

So long as the West Pakistan electric power system remains without interconnection between the major markets, the capacity constraints of Equation 1.1 must be met independently in each power market by any generating program or "strategy." When interconnection is introduced, the constraints may be met on a systemwide basis, taking into account the maximum load limits on each of the transmission lines. Each intermarket transmission system which might be constructed during the planning period is introduced as an individual project, W_c, c = 1, . . . *c*, where the subscripts identify the particular transmission system envisaged. A transmission system is defined by the capacities of the various lines, which are treated as constraints, in each year of the plan period. Any number of combinations of generating strategies and intermarket transmission programs may be compared using the simulation model so long as each is able to serve the demand in all markets with the required level of technical reserve.

TOTAL SYSTEM COST

Each power plant which meets the constraints identified in Equation 1, on an individual market basis if interconnection does not exist and on a systemwide basis if interconnection has been introduced, has an associated time profile of capital costs, maintenance and operating expenditures and fuel costs. The present worth of these cost streams is used to compare the relative merits of alternative power programs. The purpose of the planning model is to find that particular combination of generation strategy, X, and transmission program, W_c, which has the lowest value of $G(X,W_c)$ where

$$G(X,W_c) = \sum_i \{[(1+\pi)^{-i}][K_i(X) + M(x_i) + F_1(x_i,W_c) + F_2(x_i,W_c) + d_{ci} + gf_{ci} + m_{ci}]\} - (1+\pi)^{-N}\,\Gamma(x_N,W_c) \quad \text{(Equation 2)}$$

where $i = 1, \ldots, N$

$$1 \leqslant c \leqslant c$$

The term in the first set of square brackets on the right hand side is the appropriate discount factor. It is multiplied by the sum of the terms in the second set of square brackets: capital, maintenance and operation, and fuel costs associated with the particular generation strategy and transmission plan plus capital and maintenance and operation costs for the transmission system itself. The final term is a correction for terminal conditions.

The term $K_i(X)$ represents the capital costs of new generating facilities, appropriately spread over the years of the construction period required for each plant; it is composed of both domestic and foreign currency components. The term $M(x_i)$ represents the sum of maintenance and operation costs required for all the plants on the system in each year of the planning period. Fuel costs are represented by $F_1(x_i, W_c)$ for Market No. 1 and by $F_2(x_i, W_c)$ for Market No. 2.[1] Finally, the costs incurred during the planning period include the domestic and foreign capital inputs to transmission line construction, d_{ci} and f_{ci} respectively, and the associated annual maintenance and operation expenditures, m_{ci}. The coefficient g is the foreign exchange rate.

The last element on the right-hand side of Equation (2), the terminal correction, makes allowance for the fact that the investments in generation and transmission capacity made over the course of the plan period will affect the costs of serving provincial electric power demand in the years following the plan period. For example, a power program composed primarily of conventional thermal units will impose higher fuel costs on the system in future years than one including heavy investment in hydroelectric facilities. The composition of the system in year N, the last year of the planning period, is indicated by the final column vector of the strategy matrix $x_N = (x_{1N}, \ldots, x_{jN}, \ldots x_{JN})$ and by the particular transmission system W_c which has been selected.

In the selection of appropriate values for the terminal correction (the $\Gamma(\chi_N, W_c)$ of Equation 2), attention focusses on those differences in the characteristics of the final asset structure, as implied by any strategy which is likely to have a significant influence on system costs in the years following the plan period. There are several factors to be considered:

1. Inclusion in expansion plans of different amounts of hydroelectric capacity, a facility which not only contributes a low-cost energy source to the future but which typically has a longer service life than other types of generating equipment.
2. Addition during the plan period of different amounts of base-load thermal, peaking thermal, and nuclear capacity.
3. Widely varying energy utilization patterns due to differences in the availability of major intermarket transmission facilities.
4. Retirement, over the plan period, of different combinations of old plants.
5. Occurrence of different quantities of over-capacity or excess reserve at the end of the plan period.

Depending upon the characteristics of the particular system, these five factors may require corrections for differential fuel costs, M & O expenditures, and capital outlays as between varying equipment plans.

Although these terminal corrections can be evaluated within the computer simulation program itself, in the case of the West Pakistan analysis they were handled by a separate manual calculation and then combined with the figures produced by the simulation program.[2]

[1] The computer program in its present form does not calculate fuel costs incurred in meeting the load of Market No. 3 (Upper Sind); demand in this market is small and is likely to remain so relative to Markets Nos. 1 & 2 over the next 20 years; the fuel costs involved in meeting the small load in Market No. 3 also would not vary greatly among strategies studied. All the strategies do, however, include sufficient generating capability at Mari to meet local loads as well as, where applicable, to meet part of the load in the North and/or the South. An estimate of fuel costs involved in meeting Upper Sind loads was needed for some purposes and then it was calculated by hand.

[2] This whole question of the terminal correction is discussed at length in H. D. Jacoby, *ibid.*

Fuel Cost Calculation and System Load Dispatching

The central feature of the computer model is its ability to calculate the value of the fuel cost terms, F_1 (x_1, W_c) and F_2 (x_1, W_c), for each year of the planning period; this aspect accounts for most of the complexity of the model and most of the time taken in the analysis of a development program. Evaluation of fuel costs requires the simulation of system short-run operation. There is strong interdependence between the system-generating units in existence at any point in time. The fuel cost incurred over any interval is the result of operating rules adopted to determine the contribution of each available plant to total system demand at each instant during the interval. It is necessary to approximate the result of instantaneous hourly and daily scheduling—the dispatching of the component units of a supply structure.

The method used to evaluate fuel costs should capture system operating characteristics that are of economic significance but without excessive computation expense. Likewise, the planning model should reflect system interdependency only to the level of detail necessary to make wise use of available data and to draw out aspects of short-run system operations that have a significant effect on the decisions under study.

In this model used here the system energy calculation is based on a monthly numerical approximation of the results of optimal load dispatching; i.e., the scheduling of system units to meet projected capacity and energy demand is simulated to determine the power contribution of each individual plant. The procedures involve the presentation of monthly demand data in a particular form and then observation of the sequence in which the various plants would be scheduled to meet power needs. These procedures are briefly described below.

DEMAND FOR ELECTRICITY AND THE INTEGRATED LOAD FUNCTION

The sum of the instantaneous power demands of all consumers, together with an allowance for transmission and distribution losses, makes up the instantaneous load on a power system at any moment. System load, which may be denoted P(t), is expressed in kilowatts (kw) or in megawatts (1 mw = 1,000 kw). A typical daily system load profile is depicted on the left hand side of Figure 9-2. The most important indicators of demand in the interval T are the maximum instantaneous system load, P_{maxT}, and the minimum instantaneous load, P_{minT}. Total energy consumption in the period, which is expressed in kilowatt-hours (kwh), megawatt-hours (1 mwh = 1,000 kwh) and gigawatt-hours (1 gwh = 1,000,000 kwh), may be denoted E_T; it is the area under the load curve P(t). Another simple indicator of demand structure is the system load factor, L_T, the ratio between average load in kilowatts over the period and peak load in the period.

Given data on P(t), it is possible to construct certain curves or functions which convey a great deal of information about the structure of market demand. One such is the integrated load function, and the right-hand side of Figure 9-2 depicts an integrated load function corresponding to the load profile shown on the left. Each point on the integrated load function, E(v), indicates the proportion of total energy required in the period (measured along the horizontal axis) that is demanded at an instantaneous load equal to or less than that indicated by the corresponding point on the vertical axis, for instance point v_1.

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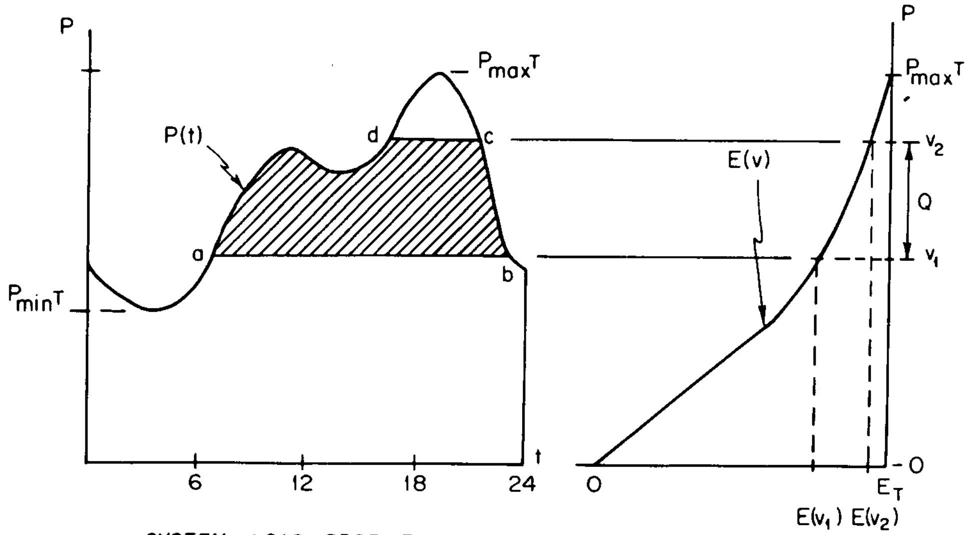
FIGURE 9.2



SYSTEM LOAD PROFILE
(TYPICAL DAY)

INTEGRATED LOAD FUNCTION

USE OF THE INTEGRATED LOAD FUNCTION

The integrated load function is a key component of the model of system energy generation used in the computer program. Although Figure 9-2 relates to too short a time period to give a realistic representation of the way the integrated load function is used in the model, nevertheless it usefully illustrates the principle of scheduling individual generating units to meet demand. Assume that there is on the system a particular generating unit of capacity Q. Under the operating policy being followed, this particular unit begins generating when the system instantaneous load reaches v_1; on the day shown this occurs at about 7 a.m. The unit carries the increase in load above v_1, up to the level v_2, where $v_2 = v_1 + Q$. It generates energy equal to the shaded area abcd. This same quantity of energy may be read directly from the integrated load function for the day shown and is equal to $E(v_2) - E(v_1)$. The pair of values for v_1 and v_2 selected for a particular plant define a load position for the unit in question. By assigning such a position to each of the plants on the system, the total amount of energy to be generated over the interval may be allocated among the individual generating units. In the following discussion the integrated load function generally is stated as $E(P)_T$, where P refers to the upper or lower limit of the operating position of a particular unit over the time interval T.

Complete definition of $E(P)_T$ for a number of future periods is not feasible; methods for forecasting the exact path of $P(t)$ are lacking, and even if such information were available, the data management problem would be quite serious, particularly in a study conducted on a monthly basis. However, it is possible to forecast P_{minT} and L_T with a degree of confidence roughly equivalent to that attached to projections of P_{maxT}, and on the basis of these three parameters it is possible to reach a reasonable approximation to $E(P)_T$. The function $E(P)_T$ is really composed of two segments: it is a straight line for all $O < P \leqslant P_{minT}$ and it is curvilinear for all $P_{minT} < P \leqslant P_{maxT}$. The straight line segment is fully defined by the three load parameters mentioned: if extended beyond P_{minT} it would intersect the P axis at the point $P = P_{maxT} \cdot L_T$. The curvilinear segment may be approximated by a quadratic equation[1] of the form (with the T subscripts omitted for the sake of clarity of presentation):

$$P^2 + a_1PE + a_2P + a_3E + a_4 = 0 \tag{3}$$

where

$$a_1 = \frac{L[2L(P_{min}/P_{max}) - 2L - (P_{min}/P_{max})^2 + 1]}{(L - P_{min}/P_{max})^2} \tag{4}$$

$$a_2 = \frac{-L[2L(P_{min}/P_{max}) - 2L - (P_{min}/P_{max})^2 + 1]}{(L - P_{min}/P_{max})^2} - 2 \tag{5}$$

$$a_3 = \frac{L^2 + 2(P_{min}/P_{max})^2\, L - (P_{min}/P_{max})^2\, L^2 - 2(P_{min}/P_{max})\, L}{(L - P_{min}/P_{max})^2} \tag{6}$$

$$a_4 = \frac{(P_{min}/P_{max})^2\,(L - 1)^2}{(L - P_{min}/P_{max})^2} \tag{7}$$

Thus the four parameters a_1, a_2, a_3, a_4 can be completely defined in terms of the values of P_{maxT}, L_T and P_{minT}. The algebra is a bit cumbersome, but it is the type of computation which a digital computer can handle with ease. The curvilinear segment of the function is a hyperbola.

Comparisons with available data from the major markets of West Pakistan (monthly time interval) have shown this to be a close approximation to the integrated load functions encountered in practice. This procedure is efficient in that it uses all the data which it seems reasonable to generate about demand in future periods. Yet it provides a function which allows the analysis of system energy generation in considerable detail.

Dispatch of Hydroelectric Units

The shape of the integrated load function in any month of the planning period establishes the basis for simulation of the optimal dispatch of the generating units available on the system in that month. Since the short-run marginal cost of hydroelectric energy is virtually zero, the hydro units are dispatched first.

The computer program, as written, can cope with the case of several hydroelectric plants in existence at the same time. But first it is convenient to consider the optimal dispatch of a single hydroelectric unit. The exposition is simplified by omitting the time subscript, T, in the notation, but it should be remembered that in practice the hydro plant energy and capacity characteristics, like the load characteristics, will change from one period to the next. Assume a single hydro-

[1] For the full derivation, see H. D. Jacoby, *ibid.*

electric plant U_j. The supply characteristics of the plant are defined over the same time interval as market demand, a month, and they are represented by Q_j, the maximum instantaneous output which the plant can attain and by H_j, the total energy it can produce over the time interval. Let these plant supply characteristics be expressed in normalized form as

$$q_j = Q_j/P_{max} \quad \text{and} \quad h_j = H_j/E$$

And let the market demand characteristics also be expressed in normalized form as

$$p = P/P_{max}, \quad \hat{p} = P_{min}/P_{max}, \quad \text{and } e(p) = E(P)/E.$$

Let the upper limit of the load position to which the hydroelectric unit is assigned be denoted $\bar{p}_j$ and the lower limit p_j.

The first priority of the hydro dispatching routine is to schedule the operation of hydro machines so as to utilize as much as possible of available hydro energy, h_j. That is to say,

$$\max \{e(\hat{p}_j) - e(p_j)\} \tag{8}$$

subject to the constraints

$$e(\hat{p}_j) - e(p_j) \leqslant h_j \tag{9}$$

and

$$\hat{p}_j - p_j \leqslant q_j \tag{10}$$

Any energy not dispatched during the interval is lost forever while the energy actually fed to the system displaces fuel consumption by thermal plants.

A second priority objective of the routine is to utilize as much of the capacity of the hydro unit as possible. If it is possible to dispatch all of h_j at a number of feasible pairs of p_j and p_j, then choose that pair or load position which will

$$\max \{\hat{p}_j - p_j\} \tag{11}$$

subject to constraint expressed in Equation 10. Given a certain quantity of usable hydro energy, total system fuel cost is minimized by dispatching that energy in such a way as to support as much of market capacity demand as the unit can carry. In practical terms, this means that a plant should be used in peaking service insofar as possible without wasting energy. This serves to minimize fuel cost because it minimizes the total amount of thermal capacity which must be brought into the market. Better use is made of more efficient thermal plants and fewer old, high-cost, machines need be called into service.

For a particular hydro plant characterized by q_j and h_j, there is, in general, only one load position (i.e., only one pair of $\hat{p}_j$ and p_j) that satisfies the objectives of the dispatching routine laid out in Equations 8–11. Depending upon the relative size of the hydro plant in relation to total market demand, however, there are five distinct cases which a dispatching algorithm must be able to consider. Several tests are required to determine which case is applicable for a particular dispatch, but once this has been accomplished, it is possible to solve directly for the optimal values of $\hat{p}_j$ and p_j.

Let the dispatching algorithm be represented by the following pair of functions:

$$\hat{p}_j = \hat{p}(\hat{p}, L, q_j, h_j) \tag{12}$$

and

$$p_j = p(\hat{p}, L, q_j, h_j) \tag{13}$$

The exact form of these functions depends upon the characteristics of plant and market, and the five different possible combinations of these are discussed below.

1. The Base Load Case. Base load refers to those values of p such that $p \leqslant \hat{p}$. If

$$q_j \leqslant \hat{p} \quad \text{and} \quad h_j = q_j/L$$

then the entire plant capacity may be dispatched on base load. All the energy generated is usable. The optimal dispatch is the following:

$$\hat{p}_j = q_j; \quad p_j = 0 \tag{14}$$

2. The Base Load Case with Surplus Energy. Following the previous case let $\hat{p}_j = q_j$ and $p_j = 0$. If

$$q_j > \hat{p} \quad \text{and} \quad h_j > e(\hat{p}_j) - e(p_j)$$

then the hydro plant covers all the base load (i.e., the load below $\hat{p}$) and some portion of peak load. In addition, there exists surplus energy which cannot be utilized. The optimal dispatch point is

$$\hat{p}_j = q_j; \quad p_j = 0, \tag{15}$$

as in the former case, but now the total energy utilized is less than h_j. This is the only case which yields surplus energy.

3. The Semipeak Load Case. If the situation fails to meet the tests for inclusion in either of the categories defined above, but it is found that when $p_j = \hat{p}$ and $\hat{p}_j = \hat{p} + q_j$ the relative sizes of plant and market are such that $h_j \geqslant e(\hat{p}_j) - e(p_j)$, then the plant is dispatched in a semipeak load position. If the load position assigned is entirely above $\hat{p}$ the plant will be able to produce more energy than is required, but at the optimum dispatch position the above relationship will be an equality: p_j will lie on the curved portion of the function (above $\hat{p}$) and p_j will lie on the straight line segment (below $\hat{p}$). Because of the convexity of e(p) there is in fact only one load position which will allow full utilization of plant energy and capacity under these conditions, and it may be defined as:[1]

$$\hat{p}_j = \frac{-\alpha_2 + \sqrt{\alpha_2{}^2 - 4\alpha_1\alpha_2}}{2\alpha_1}; \; p_j = \hat{p}_j - q_j; \tag{16}$$

where

$$\alpha_1 = a_1 + L,$$

$$\alpha_2 = a_1 h_j L - a_1 q_j + a_2 L + a_3,$$

and

$$\alpha_3 = a_3 h_j L - a_3 q_j + a_4 L,$$

the "a" terms a_1, a_2, a_3 and a_4 being defined as in Equations 4–5 above.

4. The Peak Load Case. This situation fails to come within the scope of Case 3 above because when $p_j = \hat{p}$ and $\hat{p}_j = \hat{p} + q_j$,

$$h_j < e(\hat{p}_j) - e(p_j). \tag{17}$$

However it is also found that when $p_j = 1$ and $p_j = 1 - q_j$,

$$h_j \geqslant e(p_j) - e(p_j). \tag{18}$$

[1] For details of the derivation of these optimal dispatch equations, see H. D. Jacoby, *ibid.*

The optimum load position is where these relationships are equalities, i.e., where all the energy will be utilized. The two sets of tests indicate that for this to occur both $\hat{p}_j$ and p_j must lie on the curved portion of the function. The optimal dispatch may be calculated as

$$\hat{p}_j = \frac{-\alpha_2 + \sqrt{\alpha_2^2 - 4\alpha_1\alpha_3}}{2\alpha_1}$$

$$p_j = \hat{p}_j - q_j$$

where

$$\alpha_1 = a_1q_j + a_1^2h_j$$
$$\alpha_2 = 2a_1a_3h_j - a_1^2q_jh_j - a_1q_j^2 + 2a_3q_j,$$

and

$$\alpha_3 = a_2a_3q_j + a_3^2h_j - a_1a_3q_jh_j - a_1a_4q_j - a_3q_j^2,$$

the terms a_1, a_2, a_3 and a_4 once again being defined as in Equations 4–7 above.

5. The Peak Load Case with Excess Capacity. Situations of this type meet the first test shown above for inclusion under Case 4 but it is found that when $\hat{p}_j = 1$ and $p_j = 1 - q_j$, then

$$h_j < e(\hat{p}_j) - e(p_j).$$

In other words the energy available from the plant is too small, relative to the capacity, to cover energy requirements even at the sharpest peak of the load. The solution is to dispatch not the full capacity of the plant but as much of it as can be used within the limit set by available energy. The procedure is as follows. Set $\hat{p} = 1$. It is known that, at the point of optimal dispatch,

$$h_j = e(\hat{p}_j) - e(p_j) = 1 - e(p_j),$$

but it is not known which segment of e(p) is relevant. A separate test is required. If

$$h_j \geqslant 1 - e(\hat{p}),$$

then there is sufficient energy to cover all demand above $\hat{p}$; p_j falls on the straight line portion of e(p). The best load position may be calculated as

$$\hat{p}_j = 1; p_j = (1 - h_j)\,L. \tag{19}$$

If, on the other hand,

$$h_j < 1 - e(p)$$

then p_j falls on the curved portion of e(p). The optimum dispatch position may be defined as

$$\hat{p}_j = 1; \qquad p_j = \frac{-\alpha_1 - \sqrt{\alpha_1^2 - 4\alpha_2}}{2} \tag{20}$$

where

$$\alpha_1 = a_1 + a_2 - a_1h_j$$

and

$$\alpha_2 = (1 - h_j)\,a_3 + a_4,$$

with the terms a_1, a_2, a_3, and a_4 defined as before.

It is clear from this brief description of the optimal dispatch rules that, when there are several hydro plants on the system, straight application of the rules may result in overlaps—two or more plants being assigned to the same portion of the load—which are obviously unrealistic. To deal with these cases, a procedure for joint dispatching of all overlapping units is required. The simple sequential procedure employed involves a series of steps and rules for determining the moves from one step to another. Each plant, U_j, is treated in turn and a block of hydroelectric capacity and energy, consisting of that plant alone, is defined. The block is dispatched, and tests are made to see if there is overlap between this block and any block dispatched earlier in the sequence.[1] If so, the two conflicting blocks are aggregated and dispatched as though they were one unit, following the rules prescribed above. If no further conflict exists the next plant is selected and the process begins again. The block dispatch results may be translated into operating rules for the individual plants which make up the block.

Transmission of Hydro Energy to the South

After the hydroelectric plants have been dispatched against Northern Grid loads according to the procedures described in the preceding section, the computer program goes on to consider the possibility of transmitting hydroenergy to the South (Market No. 2). Since an EHV link between the North and the South will not exist in the initial years of any expansion plan, there would be no possibility of such transmission and the computer program would jump directly to dispatching the thermal units available in the North and in the South. However, in most of the investment plans considered, transmission from North to South comes to play an important role in the later years; therefore, it is convenient to consider such transmission at this point—the computer program deals with it immediately following dispatch of the Northern Grid hydro plants.

The computer algorithm described below, which is intended to reflect the manner in which the power system of West Pakistan might best be operated in coming years, takes account of institutional as well as technical consideration. For a different system, the details of the transmission algorithm would have to be revised, although the basic approach would be the same. Subject to the constraints set by availability and capacity of transmission lines, the operating rules assumed in the study of West Pakistan power system development are as follows:

1. The Northern hydro plants will be dispatched primarily into the Northern Market. Transmission of hydro power to the South will take place only under the following two conditions:

— If the Southern Market is in a shortage condition without power from the North, then a mandatory transmission will be made so long as this shipment will not force the North into shortage.

— If there is hydro energy which cannot be utilized in the North, an attempt will be made to transmit the surplus to the South in such a way as to maximize the total quantity of hydro energy actually utilized in the two markets.

In addition, Northern hydro power will not be dispatched into pure peaking service in the South. If any transmission is made, it must first cover a portion of the Southern base load. Only if this requirement is met can the transmitted capacity and energy be dispatched in peak load service.

[1] For fuller description of this block dispatch technique see H. D. Jacoby, *ibid.*

2. There will be no transmission or thermal power between the North and the South. Because of this assumption, no provision need be made for studying transmission from the South to Mari.

3. Any thermal capacity at Mari is always available for dispatch into the Southern Market. In the event that no hydro power is moving from North to South, Mari machines may also be dispatched into the Northern Market. The allocation of the Mari capacity between North and South in such a situation will be conducted so as to minimize the total fuel cost of the integrated system.

The routine designed to model monthly system energy dispatch under these conditions is summarized in the flow chart presented in Figure 9-3. The figure shows that choice of the quantity of hydro power to be transmitted to the South is based upon an iterative calculation. The main transmission algorithm used, described below, is designed to deal with the case where the hydro plants produce more energy than can be absorbed in the North. As before the time subscripts T and i will be dropped from all variables or functions to simplify the presentation. The subscripts indicating markets of origin and destination for the transmission lines will also be omitted since all the discussion at this point is concerned with transmission from Market No. 1 (North) to Market No. 2 (South). Thus the transmission constraint is denoted V^*, the quantity of power transmitted V, and the incremental amounts of power evaluated in each iteration V.

The value of V^* in any particular period is limited to the capacity of the link between the North and Mari (with a slight downward adjustment for losses between Mari and the South) or that of the link between Mari and the South, whichever is the smaller:

$$V^* = \min\,[V^*_{3,2},\ (1 - \Lambda)\ V^*_{1,3}], \tag{21}$$

where Λ is the percentage loss in transmission between Mari and the South. The transmission constraints $V^*_{3,2}$ and $V^*_{1,3}$ are defined at the receiving end of each line, net of the losses occurring on the lines they describe.

Any hydroelectric energy not actually dispatched in a period is presumed lost. Therefore the objective of the algorithm regarding transmission of hydro-energy excess to Northern Grid requirements is to maximize the total quantity of hydro-energy actually utilized in the two markets, i.e., to minimize the sum of surplus energy in the North plus transmission losses. The blocks in which hydro power is dispatched were referred to at the end of the last section. The block which is relevant here is one which falls under Case 2 of the hydro dispatching routine—The Base Load Case with Surplus Energy—for which $P_k = 0$ and $\bar{P}_k > P_{min,1}$, where $P_{min,1}$ indicates the minimum monthly demand in Market No. 1, the North. Such a block may be denoted B_k. The task of the transmission routine is to identify the plant U_j which had the most excess energy of those dispatched in the block B_k and to determine whether the shipment of an increment of capacity, ΔV, from that plant will yield an improved overall utilization of available hydro energy.

There are four restrictions on the size of the increment of capacity that may be selected for transmission. Each increment, ΔV, along with other transmission variables, is defined as of the receiving end of the connection. Thus the size of ΔV cannot be so large as to make the magnitude of the total transmission for the month, V, greater than the transmission line constraint, V^*. Second, ΔV is limited to the size of the standard transmission increment, V, which is an input datum. The selection of a

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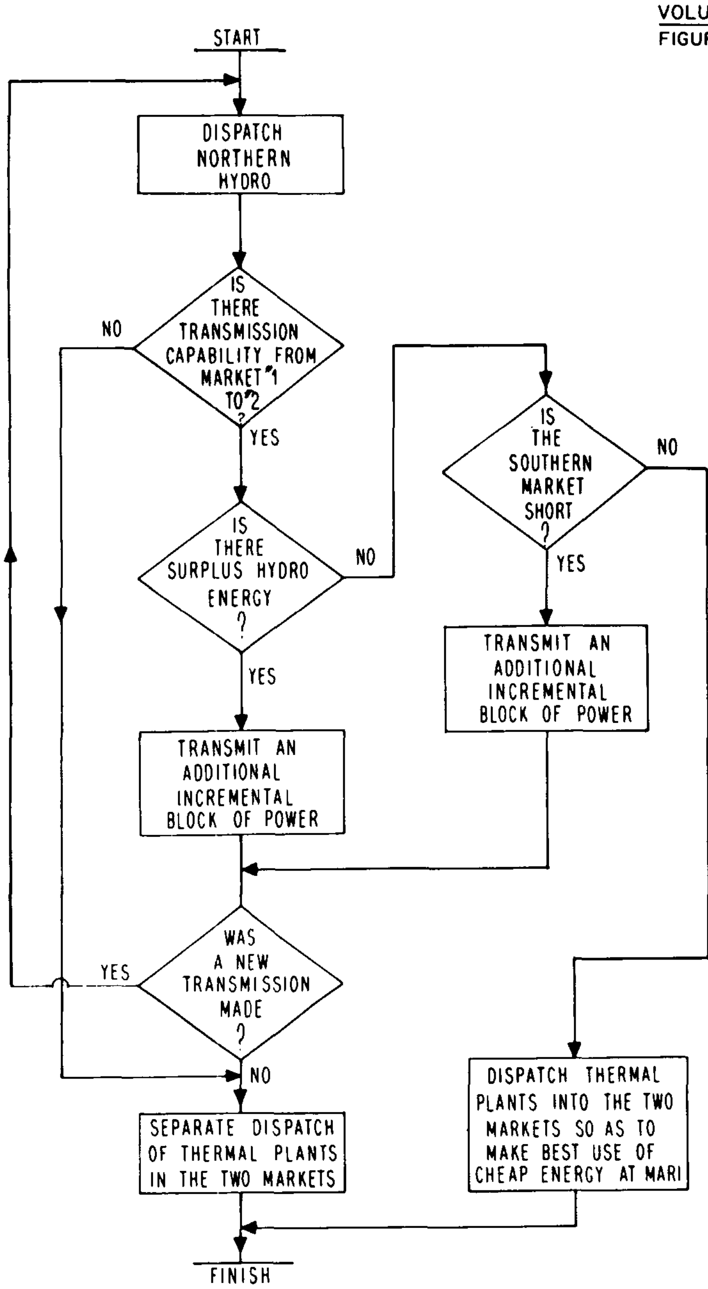
FIGURE 9.3



SYSTEM ENERGY DISPATCH ROUTINE

value for V involves consideration of the warranted accuracy of the computation and the computer time required to evaluate each strategy. In most calculations for the West Pakistan case, $V = 50$ mw. A third limitation is that the increment in capacity delivered to the South cannot be greater than the capacity of the particular hydro plant, U_j, chosen to transmit with due account taken of losses in transmission. Finally, the incremental transmission may not be so large as to force the Northern Market into shortage. Thus the magnitude of an incremental amount of power to be added to the transmission for the month is determined as

$$\Delta V = \min\left\{[V^* - V],\ V,\ \frac{Q_j}{(1-\Lambda)^2},\ \left[\sum_{k=1}^{J-j} (\bar{P}_k - P_k) + \sum_{j=1} (Q_{j,1}) - P_{max,1}\right](1-\Lambda)^{-2}\right\} \tag{22}$$

Once the size of ΔV (in megawatts) has been determined, the next step is to determine the amount of energy available to go with it. Let $Y_1(\Delta V)$ denote the amount of energy associated with the capability ΔV at the generating plant in Market No. 1 and $Y_2(\Delta V)$ denote the amount of energy associated with ΔV at the receiving end of the transmission line in Market No. 2. In order to add ΔV to the transmission to the South, the contribution of plant U_j to the Northern Market must be reduced by $\Delta V(1 - \Lambda)^{-2}$, since losses Λ, assumed to be of equal size on both the North-Mari and the Mari-South links of the transmission line, are incurred in the course of transmission. Of necessity such a cutback in capacity dispatch frees additional hydro energy, i.e., $Y_1(\Delta V) > E_j$, where E_j is the amount of surplus energy available initially when all the capacity was dispatched into the Northern Market under hydro-dispatch Case 2. Exactly how much additional surplus is created depends on the manner in which the cutback is performed. Since the objective of the whole routine is to utilize as much hydro energy as possible, the desired procedure for determining the cutback is the one which frees the least amount of additional energy; the convexity of the integrated load function means that this requirement can best be met by simply reducing the upper limit $\bar{P}_j$ of the load position in the Northern Grid originally assigned to plant U_j. Thus if $\bar{P}_j$ is set as ${}_j\bar{P} = P_j + Q_j - [\Delta V/(1 - \Lambda)^2]$ then the total amount of surplus energy available for the shipment to the South from this plant is

$$Y_1(\Delta V) = H_j - [E_1(\bar{P}_j) - E_1(P_j)] \tag{23}$$

In other words, $Y_1(\Delta V)$ is the total energy available at the plant minus the energy dispatched into the Northern Market at the reduced capacity level.

From the viewpoint of the Southern Market, the power coming in over the transmission line is treated as if it originated at a dummy hydro plant $U_{j,i=1}$. The load position assigned to the transmitted capacity and energy is defined in terms of the upper and lower limits of the range of Southern capacity demand served by this dummy unit $\bar{P}_j$ and P_j. Before the first cycle through the transmission routine, a value is assigned to P_j, and $\bar{P}_j$ is set equal to P_j. In some situations it might be appropriate to set P_j initially at zero, but in the West Pakistan application P_j was given a positive initial value in order always to reserve a certain portion of base load for the nuclear plant now under construction near Karachi. With each iteration an additional block of transmitted capacity, ΔV, is added to $\bar{P}_j$ and thus, over the course of the computation, the size of the dummy plant grows. To support each ΔV a certain quantity of energy, $Y_2(\Delta V)$, is required:

$$Y_2(\Delta V) = E_2(\bar{P}_j + \Delta V) - E_2(\bar{P}_j) \tag{24}$$

When the full hydro transmission for the month has been established then $(\bar{P}_j - P_j) = V$, where V is the total hydro capacity delivered to the South.

However, before each ΔV is added to the amount to be transmitted to the South two tests are required to check that such additional transmission is feasible and worthwhile. First a check must be made to ensure that there is sufficient energy available from the hydro plant U_j to meet the energy demand in the South at the position on the load curve assigned to ΔV, i.e.

$$Y_2(\Delta V) \leqslant \frac{Y_1(\Delta V)}{(1 - \Lambda)^2} \tag{25}$$

The second test ensures that transmission of ΔV will make a net addition to the amount of hydro-energy available for sale to consumers:

$$E_j - [Y_1(\Delta V) - Y_2(\Delta V)] > 0 \tag{26}$$

The term E_j is the surplus energy available at plant U_j before the transmission, and for the transmission to be worthwhile it must exceed the waste involved in transmission, due either to transmission losses or to inability of the Southern market to absorb all the energy which could be made available with ΔV.

As each ΔV that proves feasible and worthwhile is added to the amount allowed for transmission to the South, the computer program returns to redispatch the Northern hydro system under the new conditions of reduced availability of hydro power for use in the North and the analysis recommences with another ΔV. When no further possible increments to transmission can be identified or when none of those possible pass the two tests cited in the last paragraph, then the routine for the transmission of surplus hydro-energy is completed.

This algorithm for dealing with excess hydroenergy in the North appears to maximize total energy utilized in a large majority of the months of the planning period, although it can be shown that there are certain conditions under which it may not indicate the best possible pattern of use of available energy. Efforts to develop a routine which could handle the simultaneous joint dispatch of hydro units into both markets without infringing constraints on transmission line capacity, etc. proved unproductive. The algorithm described above was developed with a view to several of the specific characteristics the West Pakistan power system will likely have. First, the relative sizes of the Southern Market demand and the planned transmission system are such that well over half the capacity transmitted south will always be dispatched on base load. Second, since the primary purpose of the market interconnection is to allow utilization of surplus hydro-energy in the South, any strategy which provides for interconnection also involves a large amount of hydro capacity in the North. Third, the capacity and energy output from the various hydro units varies considerably between the wet and dry seasons. During months of high river flow, the transmission line constraint V* is normally binding for deliveries to the South and total energy usable in the North is limited by the amount of hydro capacity left over after transmission; all capacity is utilized and no other transmission schedule can increase the amount of energy absorbed. In the dry months, when the head on the turbines is relatively low and the output of the hydro plants is sharply reduced, the transmission is more likely to be limited by the total capacity needed to meet Northern Market demand; the North is left with the bare minimum of hydro and thermal capacity required to meet its own peak load, but the demand for energy there may still sometimes be too small to absorb all the hydro energy remaining after as much capacity as possible has been dispatched to the South. In some months, virtually all the surplus energy is absorbed; to cut computation time a tolerance limit of 10 gwh was placed on excess energy and when E is below this no further transmissions are tested. A more refined transmission routine would probably result in some changes in the pattern of hydroenergy utilization: perhaps permitting somewhat greater absorption (e.g. at Mari) or involving more peak use of hydroenergy in the South (hence leaving a better position for local thermal units) a lower total volume of transmission (hence transmission losses), or securing a better pattern of sources of power for dispatch South. But the net difference in system cost between simulations using a more complex set of rules and those based on the operating rules developed here would not be great.

As pointed out, there is one special case in which allowance must be made for transmitting of hydroenergy South even though no significant amount of excess energy exists in the North. This is where the sum of the capacity in place in the South plus the hydro power already coming in from the North (under the procedure described above), plus the additional capacity which may be shipped from Mari, is not sufficient to cover peak demand in the South.

$$\sum_j Q_{j,2} + V + (\sum Q_{j,3})(1 - \Lambda) < P_{max,2}, j = 1, \ldots, j. \tag{27}$$

This is rare, but when it does occur an additional mandatory transmission is required and more of the thermal plants in the North have to be used to meet load there than would otherwise have been necessary. The procedure adopted for handling this case is very similar to that described above except that the hydro plant producing the most total energy rather than the most excess energy is initially selected as a potential source of power for the South. The feasibility test is

$$H_j > \frac{Y_2(\Delta V)}{(1 - \Lambda)^2} \tag{28}$$

with $Y_2(\Delta V)$ calculated as shown above in Equations 24–25. The test as to whether or not the transmission is worthwhile (Equation 26) is of course omitted.

Dispatch of Thermal Units

Once the hydro dispatch in the North and the transmission to the South have been completed, the program begins the dispatch of thermal units. Each market, No. 1 and No. 2, is dispatched in turn in such a way as to minimize the market fuel cost for that month.

Fuel is by far the most important element in the variable costs of running thermal power stations. Each generator or group of generators within a station has a production function which represents fuel efficiency per unit of output or load. This usually is referred to as the specific consumption or the heat rate of the unit; with the application of a fuel price, it becomes a cost curve of the form $C_j[Q_j(t)]$ where $Q_j(t)$ is the instantaneous load on the j^{th} plant. Each of these production functions already represents a complicated optimization within the technical process of electricity generation—optimization of boiler and condenser operation, steam temperatures and pressures, etc. The task of the load dispatcher responsible for controlling the operation of an all-thermal system is to maintain

$$\sum_j Q_j(t)\, x_{ji} = P(t), \qquad j = 1, \ldots, \mathit{j} \tag{29}$$

in such a way as to minimize fuel consumption, given the generating units available for service and their cost functions. In principle minimization of system costs involves the equating of marginal costs, $C'_j[Q_j(t)]$ over all plants.

It is reasonable, for purposes of long-run planning for most systems, to represent the heat rate of each plant, $C_j[Q_j(t)]$, by a constant, $\bar{C}_j$, over the relevant range of $Q_j(t)$. The point of most efficient output for most large steam-electric generating units is in the region of 75–80 percent of rated output capacity. Above and below this point the heat rate increases, but even at rated output it is not far above that at the most efficient point. Moreover because technological change in electric power generation has been quite dramatic in recent decades, newer plant in most systems is both larger and significantly more efficient than the older plant. Newer plants tend to be run on base load and then, as load builds up in the early morning, the older less efficient units are brought on at a fairly high level of load. In the aggregate this means that most plants operate in a relatively narrow kw range about their most efficient output points, and within this range the variation in $C_j[Q_j(t)]$ is small relative to interplant differences in heat rate. On the average a typical plant will operate at about 85 percent of rated capacity; this percentage is referred to as the plant factor. And, on the average, a typical plant will generate at a level of fuel consumption per kwh, $\bar{C}_j$, slightly above the minimum value of $C_j[Q_j(t)]$.

In the computer model, the subset of plants in existence in each power market in each year of the planning period is indicated by the matrix of scale variables $\|x_{ji}\|$; $j = 1, \ldots j; i = 1, \ldots, N$. For any particular year, i, the plants in existence are noted by a j-element column vector of zeros and ones, $x_1 = [x_1{}^i, \ldots, x_{\mathit{j}i}]$. Let f_j denote the fuel price in \$/million BTU for plant j. The computer program ranks all the thermal plants available in each year in order of their fuel cost per kwh sent out, such that $\bar{C}_j f_j \leqslant \bar{C}_{j+1} f_{j+1} \leqslant \bar{C}_{j+2} f_{j+2} \ldots$ for $j = 1, \ldots, \mathit{j} - 1$. The plants are then dispatched in this order using the integrated load function, the first plant (with lowest fuel cost per kwh) being assigned the lowest available load position on the curve. If $\bar{P}_j$ is the upper limit, then the total fuel cost incurred in any individual market is calculated as

$$F(x_i) = \sum_j \bar{C}_j f_j [E(\bar{P}_j)_T - E(P_j)_T],\ j = 1, \ldots, \mathit{j}.$$

In an all-thermal system, such as in the South until interconnection makes hydroenergy available, the following relations will hold:

$$\begin{array}{lll} (1) & P_j = 0 & \text{for } j = 1, \\ (2) & P_j = {}_j\bar{p}_{-1} & \text{for } j = 2, \ldots, \mathit{j}, \\ (3) & \bar{P}_j = P_j + w_j Q_j x_{ji} & \text{for } j = 1, \ldots, \mathit{j}, \end{array}$$

Where W_j is the plant factor defined above; and $E(\overline{P}_j)_T$ will have an upper limit of E_T, the total energy to be generated during the period. In a system including hydroplants, some of the load will be preempted by hydro energy dispatched in the manner described in previous sections. The computer program proceeds by dispatching the thermal plants in ascending order of their fuel cost per kwh sent out, but after dispatching each plant a check is made to see that the load position assigned is not already occupied by a hydroplant, and if it is, then the load position of the thermal plant is adjusted accordingly.

Transmission of Thermal Power from Mari

To this stage, all the hydro units have been assigned their final dispatch and a preliminary dispatch has been made of the thermal units in existence in the North and the South against the loads of their respective markets. However, if there exists generating capacity in the Upper Sind (Mari) and if a full EHV transmission system from Lyallpur to Karachi is in place, the program must consider the possibility of transmission from Mari in either direction (provided that the line from Lyallpur to Mari is not already loaded with hydroenergy coming South). Being located directly on the gas field, the Mari machines may be among the cheapest on the system as far as fuel cost is concerned. The objective of the thermal transmission algorithm is to allocate any capacity at Mari which is surplus to local requirements between the two markets in such a way as to minimize overall system fuel expenditure.[1]

The allocation of Mari capacity between the two markets is denoted by the variables γ_1 and γ_2 where

$$\gamma_1 = \frac{V_{3,1}}{\sum_j Q_{j,3}}, \qquad \text{and} \qquad \gamma_2 = \frac{V_{3,2}}{\sum_j Q_{j,3}}, \; j = 1, \ldots, j \tag{30}$$

The overall system fuel cost function to be minimized may be expressed as

$$Z = F_1(x_i, W_c, \gamma_1) + F_2(x_i, W_c, \gamma_2) \tag{31}$$

The thermal transmission routine proceeds by adopting as a starting point the maximum delivery of Mari power that can be made to the North without leaving the South short of capacity and then transferring portions of this amount to the South, checking each time to see whether such a transfer serves to lower total system fuel costs. The routine is completed when the particular allocation of Mari capacity that minimizes total system fuel costs has been identified.

[1] Note that this is not an optimization of the overall system energy dispatch but a suboptimization of the thermal scheduling subject to the hydro dispatch and transmission yielded by the routines described above. One of the operating assumptions chosen for the interconnected system stated that, in the absence of capacity shortage in the Southern Market, no transmission is to be made from North to South if there is no surplus hydro energy. This thermal transmission routine is designed to minimize fuel cost under these circumstances. This does not mean that some other operating assumption for the hydro transmission—for example, transmitting even when there is no surplus—might not yield an even lower overall system fuel consumption.

The initial allocation of Mari capacity to the South may be defined as follows:

$$V_{3,2} = \min \{V^*_{3,2}, \left(\sum_j Q_{j,3}\right)(1 - \Lambda), \max [\left(P_{max,2} - \sum_j Q_{j,2}, \right)\left(\sum_j Q_{j,3}(1 - \Lambda) - V^*_{3,1}\right)]\}, j = 1, \ldots, j. \quad (32)$$

Equation 7.3 says the following: first, the transmission to the South can be no larger than the size of the transmission line or the total capacity of the Mari units adjusted for transmission losses; subject to these limits, however, the initial allocation south should be enough to cover any potential shortage in the Southern Market or the total amount of capacity which cannot be sent north due to transmission constraint—whichever is greater. Whatever is left over after this initial allocation to the South is transmitted to the Northern Market subject to the appropriate line constraint:

$$V_{3,1} = \min \left\{\left(\sum_j Q_{j,3}\right)(1 - \Lambda), V^*_{3,1}\right\}, j = 1, \ldots, j. \quad (33)$$

Each of the Mari units, $U_{j,3}$, is considered available for dispatch into both markets in accordance with the shares allocated by Equations 32 and 35. In effect the routine treats each Mari plant as if one portion of its capacity were dispatched north and another portion south. Since the fuel price at all Mari units is likely to be the same, this yields a good approximation of the manner in which this generating center actually would be operated. Account is taken of the energy loss in transmission by applying a heat rate of $\bar{C}_j(1-\Lambda)^{-1}$ to each of the Mari units. The thermal dispatch of the Northern Market and that of the Southern Market are repeated in turn, according to the procedures described in the last section, taking account of the shares of Mari capacity available to them as well as their own local thermal plants. The fuel costs incurred in each of the markets are summed to give a value for the total fuel cost for the integrated system, Z, as shown in Equation 31.

In the first iteration the resultant Z is compared with a preselected value which is purposefully set high in order to force the program to a second iteration in which the Southern share of Mari is increased by 10 percent and the Northern share commensurately reduced if the Mari-Lyallpur transmission constraint is not binding. At the end of the second and subsequent iterations the figure for total system fuel costs, Z, is compared with the value of Z which resulted in the iteration immediately preceding. Increments of 10 percent in the allocation to the South for each iteration were adopted because, although smaller steps would yield greater accuracy, they would also involve a significant increase in computer time and cost. The thermal transmission routine is completed when an iteration occurs for which the value of Z is equal to or greater than the value of Z resulting from the previous iteration. The values of γ_1, γ_2, $V_{3,2}$, $V_{3,1}$ and Z developed in this previous iteration describe the optimal operation of the system during the period in question.[1]

This completes the description of the various load-dispatching algorithms used to simulate short-run operation of the West Pakistan power system. Based upon this model of system energy dispatch, the computer program calculates fuel costs in-

[1] For this iterative procedure to converge upon the minimum value of Z it is necessary that this function be convex. A proof that this is so is presented in H. D. Jacoby, *ibid.*

curred in each month of the planning period, and in turn combines these data with figures for the capital and M&O expenditures implied by a particular investment schedule to produce information on the present worth of total system supply cost over the Plan period. This calculation is performed for a range of values of the discount rate, the foreign exchange rate, fuel prices and opportunity costs of capital in order to allow the testing of the sensitivity of results to variation in assumptions about these variables.

Dimensions of the Computer Program

In the form in which it was used for these studies, the simulation program can handle a planning period of up to 20 years. In addition to demand data for the three markets, it accepts information on the characteristics of up to 40 existing and potential hydro plants. Only six hydro units may be on the system at any time, however. It can consider up to 50 existing and potential thermal and nuclear units and 10 alternative transmission systems. For purposes of the analysis, a thermal or nuclear generating unit can consist either of an individual machine (boiler, steam turbine, generator and generator transformer) or of several machines of similar operating characteristics within a particular plant. The limitations on the number of plants and length of period which the program can handle are imposed by the size of the core storage of the IBM 7090 and 7094 computers on which the program was run. With expanded use of tape or disc storage in the course of the computation larger systems could be analyzed even with smaller computers.

On an IBM 7094 computer, the complete evaluation of a 20-year development program including several separate system dispatches for each month of each year (one for each set of fuel prices) and computation of the present worth (at various different discount rates) of fuel costs, maintenance and operation costs and capital costs (with foreign exchange expenditures valued at a number of exchange rates) requires approximately four minutes; on an IBM 7090 it requires slightly longer. So long as the load forecast remains fixed, any number of alternative development programs may be simulated in a particular computer run.

Data Requirements for the Computer Program

The data required by the program are divided into two categories—permanent data and strategies. The permanent data describe the physical and economic context within which the evaluation of various alternative strategies takes place. The information contained in the permanent data deck may be broken down as follows. First, there are the characteristics of market demand:

— Monthly projections of maximum peak demand, P_{maxT}, minimum demand, P_{minT}, and load factor, L_T, over the N years of the planning period for each of the major markets.

Next there is information on each of the existing and potential thermal and nuclear generating units:

— Name of the unit.
— Number of the market in which the unit is located.
— Rated output capacity, net of in-station losses and consumption, Q_{ji}, for each year after commencement of construction.
— Unit maintenance and operation cost, m_{ji}.

— For each conventional thermal unit, a heat rate or fuel efficiency, $\bar{C}_j$.
— A range of prices for conventional fuels, f_j.
— The percentage of fuel consumption at each plant, representing a direct foreign exchange cost.
— For each nuclear unit, a composite figure for fuel cost per kwh, $\bar{C}_j f_j$.
— For each potential new plant, domestic and foreign capital cost in each year of the construction period. Duties, taxes and interest during construction are excluded from capital costs.

For each hydro development to be considered, the following data are required:

— Name of the plant.
— The monthly energy available, H_{jT}, and the monthly capacity Q_{jT}. One pair of these values is required for each month of each year of the planning period. They change over the years as more units are installed at the hydro plant. The energy and capacity figures are based on mean-year flows. For purposes other than system dispatch, e.g. scheduling of unit additions in a strategy, firm capacity figures, based on critical year flows, are used.
— Capital and maintenance and operation cost data similar to that described above for thermal plants.

Since the monthly pattern of energy and capability available from a hydroelectric project depends on the size of the reservoir and dam and on the reservoir operation policy followed, and also because the pattern changes over the years as more units are installed, a separate project must be defined for each combination of these factors one wishes to evaluate.

For each transmission system, W_c, the following data are required:
—Transmission constraints (mw) for each link for each year of the planning period:[1] $V^*_{1,3}{}^{ci}$, $V^*_{3,1}{}^{ci}$ and $V^*_{3,2}{}^{ci}$, $i = 1, \ldots, N$.
—Domestic and foreign capital cost over the construction period, d_{ci} and f_{ci}, $i = 1, \ldots, N$.
—Maintenance and operating cost, m_{ci}, $i = 1, \ldots, N$.

In addition, an estimate must be provided for the percentage loss of capacity and energy in transmission over each link, Λ. Because the distances 1,3 and 3,2 are roughly equivalent, Λ is the same for each link. It is also assumed equal for all different sizes of transmission lines. As pointed out in the description of the routine for transmission of hydro energy to the South, the size of the incremental block added in each iteration is also an input datum, V.

Then there are data on the economic condition of the public sector:[2]

— A range of values for the rate of time discount, π.
— A range of values of the foreign exchange rate, g.

[1] Note that $V^*_{3,1}$ will not normally be the same as $V^*_{1,3}$ but substantially greater. $V_{3,1}$ is effectively much shorter than $V_{1,3}$ since the former runs from Mari to the Northern Grid load center while $V_{1,3}$ really runs from Mangla or Tarbela through the Northern Grid to Mari.
[2] Note that the model is set up in such a way as to be able to accommodate a range of values for the opportunity cost of capital in addition to values for the discount rate. This facility was not employed in these studies, a single synthetic 8 percent rate of interest being used for all discounting.

This completes the data requirements of the permanent deck. In a production run, these data are used in the evaluation of a strategy deck which may contain any number of system expansion plans. Each strategy contains four types of data.

— Name of the strategy.
— Dates when old plants are retired from the system, $\bar{R}_j$.
— Dates when new units are added to the system, $\bar{S}_j$.
— Identification of the transmission system, W_c, appropriate to the strategy.

THE COMPUTER PRINTOUT

There are several sections to the computer printout. First, the whole of the permanent data deck is laid out in an orderly fashion: all the load data grouped together, a list of all existing and potential thermal plants with relevant cost and capability information, the cost data and the monthly capability and energy figures for each hydro plant in each year of the Plan period, cost and capability data for each of the three transmission lines, $V_{1,3}$ $V_{3,2}$ and $V_{3,1}$ in each year of the plan period, and finally the economic parameters. Presentation of this data may take as much as 40-50 pages, and it is followed by the analysis of each strategy. For each strategy analyzed, the computer program produces about 25-30 pages of information, which divides itself into two parts: first, two- or three-page monthly operating summaries for each year of the Plan period and second, at the end, a three-page summary of the complete strategy and a presentation of the discounted present worth of the costs involved in it.

The computer program computes a number of figures for the discounted present worth of total costs of a strategy, each figure corresponding to some different combination of assumptions about the price of fuel, the value of foreign exchange, the discount rate, and the opportunity cost of capital. The ranges between the different present-worth figures give an indication of the sensitivity of the results to changes in assumptions regarding these economic parameters. Consistency with other aspects of the Indus Special Study required that the analysis of the West Pakistan power system be made on the basis of an 8 percent discount rate; the main focus in the sensitivity analysis was on the effect of different assumptions about the price of thermal fuel and the value of foreign exchange. The present-worth figures presented in the computer printout for each strategy were adjusted by hand to allow for the terminal correction discussed earlier and for slight differences between strategies in requirements for EHV step-up and step-down transformers at the generating plants which could be handled more easily in this way than in the program itself. Duly adjusted, these figures represent values of $G(X, W_c)$, as presented in Equation 2.

The detailed monthly operating information generated by the computer program proved very useful in the evaluation of the performance of the system under different development programs and in assessment of why the total costs of any program turned out to be higher or lower than those of another program. The summaries for the last years of the planning period also provide the basis for calculation of an appropriate terminal correction. Figures 9-4 and 9-5 show the form of the system operation summary for a typical year. Where appropriate, the mathematical symbols corresponding to the figures shown are presented in the right-hand margins.

Plant Names		Market Number 1												
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
THERMAL	MUL S1		.	.22	.21	.16	.24	.07	.	.	.	.08	.	.
THERMAL	MUL S2		.	.08	.07	.05	.13	.00	.	.	.	.00	.	.
THERMAL	MUL GT		.	.01	.00	.	.07	.	.	.	.	.	.	.
THERMAL	LYA D		.	.00	.	.	.07	.	.	.	.	.	.	.
THERMAL	LAHGT1		.	.	.	.	.03	.	.	.	.	.	.	.
THERMAL	LAHGT2		.	.	.	.	.01	.	.	.	.	.	.	.
THERMAL	LYA S1		.10	.36	.34	.28	.36	.19	.00	.03	.02	.21	.07	.12	Ω_{jT}
THERMAL	Sukkur		.75	.	.42	.35	.	.	.	.	.	.	.90	.69
THERMAL	LAHGT3		.	.	.	.	.05	.	.	.	.	.	.	.
THERMAL	Mari 1		.90	.	.61	.47	.	.	.	.	.	.	.90	.90
THERMAL	Mari 2		.90	.	.56	.44	.	.	.	.	.	.	.90	.88
THERMAL	Mari P		.82	.	.49	.39	.	.	.	.	.	.	.90	.75
HYDRO	Small	Top MW	346.	749.	673.	645.	708.	923.	1093.	1156.	1204.	1063.	1157.	356.	$\leftarrow \bar{P}_k$
		Bottom MW	74.	0.	0.	0.	0.	0.	0.	0.	0.	0.	81.	72.	$\leftarrow \underline{P}_k$
		Trans MW	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
		Trans GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	WARS40	Top MW	1098.	850.	673.	645.	708.	923.	1093.	1156.	1204.	1063.	1157.	1155.
		Bottom MW	418.	750.	0.	0.	0.	0.	0.	0.	0.	0.	81.	491.
		Trans MW	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
		Trans GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	MAN10A	Top MW	346.	749.	673.	645.	708.	923.	1093.	1156.	1204.	1063.	1157.	356.
		Bottom MW	74.	0.	0.	0.	0.	0.	0.	0.	0.	0.	81.	72.
		Trans MW	0.	0.	0.	0.	150.	0.	0.	0.	0.	0.	0.	0.
		Trans GWH	0.	0.	0.	0.	109.	0.	0.	0.	0.	0.	0.	0.
	MAN50B	Top MW	1098.	749.	673.	645.	708.	923.	1093.	1156.	1204.	1063.	1157.	1155.
		Bottom MW	418.	0.	0.	0.	0.	0.	0.	0.	0.	0.	81.	491.
		Trans MW	0.	50.	0.	0.	29.	179.	179.	179.	145.	150.	0.	0.
		Trans GWH	0.	37.	0.	0.	21.	131.	131.	131.	106.	109.	0.	0.
	Excess Hydro MW		80.	0.	0.	0.	0.	0.	0.	0.	0.	0.	55.	135.
	Excess Hydro GWH		−0.	3.	12.	50.	74.	126.	164.	204.	5.	5.	0.	−0.
	Demand in MW		1098.	1192.	1196.	1090.	1121.	1162.	1098.	1239.	1264.	1302.	1157.	1155.	$\leftarrow P_{max}T,1$
	Share of Mari		.32	.	.46	.31	.	.	.	.	.	.	.18	.46	$\leftarrow Y_{T,1}$

SYSTEM OPERATION SUMMARY FOR A TYPICAL YEAR—MARKET NO. 1 (NORTHERN GRID)

	Plant Names	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
		Market Number 2												
THERMAL	KAR B	.	.	.07	.	.	.00	.00	.02	.04	.07	.03	.23	Ω_{jT}
	KAR BX	.11	.02	.22	.12	.09	.11	.11	.13	.16	.19	.18	.36	
	KAR EL	.	.	.	.	.	.	.	.	.	.	.	.03	
	KAR DF	.19	.08	.29	.19	.16	.19	.18	.20	.22	.25	.24	.42	
	KAR K1	.66	.55	.75	.64	.59	.62	.60	.62	.62	.65	.65	.83	
	KAR K2	.53	.41	.62	.51	.47	.50	.48	.50	.50	.53	.54	.71	
	HYD S1	.	.	.01	.	.	.	.	.	.	.01	.	.17	
	HYD S2	.03	.	.15	.05	.02	.04	.05	.07	.09	.12	.11	.29	
	HYD GT	.	.	.	.	.	.	.	.	.	.	.	.02	
	Sukkur	.00	.	.11	.01	.00	.02	.03	.05	.07	.10	.07	.26	
	KOT OF	.	.	.04	.	.	.	.	.	.01	.04	.00	.20	
	KOT GT	.	.	.	.	.	.	.	.	.	.	.	.07	
	HYDGT2	.	.	.	.	.	.	.	.	.	.	.	.13	
	KORA 3	.33	.22	.43	.33	.29	.32	.31	.33	.34	.37	.37	.55	
	KAR N1	.90	.90	.90	.90	.86	.87	.86	.87	.89	.89	.90	.90	
	Mari 1	.90	.90	.90	.90	.74	.78	.76	.77	.80	.83	.90	.90	
	Mari 2	.90	.83	.90	.90	.72	.75	.73	.74	.77	.80	.90	.90	
	Mari P	.82	.70	.87	.80	.68	.71	.69	.70	.71	.74	.81	.90	
	Demand in MW	596.	588.	603.	621.	640.	652.	654.	665.	677.	692.	675.	680.	$\rightarrow P_{max}T,2$
	Share of Mari	.46	.44	.33	.50	.14	.14	.14	.14	.22	.21	.56	.31	$\leftarrow Y_{T,2}$

TRANSMISSION SYSTEM MCSPO

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
North to Mari	0.	47.	0.	0.	170.	170.	170.	170.	138.	142.	0.	0.	$\leftarrow V_{1,3}$
Mari to Karachi	206.	243.	148.	225.	226.	226.	226.	226.	230.	230.	250.	140.	$\leftarrow V_{3,2}$
Mari to Lyallpur	146.	0.	205.	138.	0.	0.	0.	0.	0.	0.	81.	207.	$\leftarrow V_{3,1}$
System Reserve	699.	554.	317.	387.	554.	711.	943.	853.	832.	636.	682.	549.	

SYSTEM OPERATION SUMMARY FOR A TYPICAL YEAR—MARKET NO. 2 (SOUTH)
WITH SUMMARY OF TRANSMISSION SYSTEM OPERATION

Figure 9-4 contains the information on Market No. 1, the Northern Grid. First, data on the scheduling of thermal plants are presented in the form of monthly plant factors, Ω_{jT} where

$$\Omega_{jT} = \frac{E_{jT}}{Q_{jT}T} \tag{34}$$

The plant factor indicates the relative load position of each plant during the month —or, in other words, the extent to which the plant is used during the month to meet market demand. It was assumed as an input datum that the maximum effective load factor that could be taken by a plant would be 90 percent; W_j was set at 0.90. Therefore when $\Omega_{jT} = .90$ it means that the plant is running entirely on base load. The smaller the value of Ω_{jT} for an individual plant, the higher into the load peak the plant has been dispatched. When $\Omega_{jT} = 0$ the plant is not used at all during that month. It is also possible from these data to calculate the total fuel consumption by any plant over any period. This feature proved very useful in analysis of the differences among power programs in their total requirement of thermal fuel and in the need they implied for expansion of the gas pipelines.

Because the overall system operation adjusts to variation in fuel prices and the exchange rate, there is a set of Ω_{jT} for each combination of assumptions about these prices. Before each computation is begun a decision must be made as to which set is to be printed out. The printout shown here represents system dispatch on the basis of financial fuel prices, roughly 14¢ per million Btu for gas at Mari/Sui, 50¢ per million Btu for gas at Multan and Lyallpur, and 36¢ per million Btu for gas in Karachi.

Figure 9-4 indicates that the Northern Grid load in this particular year was partially met in some months with supplies of power from Upper Sind. The Sukkur steam station and three plants at Mari are dispatched into the Northern Grid in January, March, April, November and December. The plant load factors given for the Mari and Sukkur units in the top block of the printout refer to the load factor on the share of the Upper Sind capability which was made available to the North in that particular month; this share of Mari or Upper Sind capability is shown in the last row of the printout displayed.

The next block of information in Figure 9-4 concerns the hydro plants. Each hydro plant is presented separately, except that the eight Small Hydels were treated together as a single plant and Mangla was considered in two parts, one part on continuous base load in connection with requirements of steady releases for certain irrigation canals and the other plant available for peaking if necessary. Top MW refers to the upper limit, P_k, of the block of hydro plants to which the plant in question was assigned in this particular month for dispatching purposes. Bottom MW is the lower limit of the block, P_k; both are stated in megawatts. When several plants have been dispatched in the same block, identical values of $\bar{p}_k$ and P_k appear for each. Thus, for instance, in January of the year shown in Figure 9-4, the Mangla A units together with the Small Hydels were dispatched in one block, effectively on base load, while the remaining Mangla units (Mangla B) together with the Warsak plant were dispatched in a separate block to meet almost all the remaining load. The Mari units and the Lyallpur plant were used to fill in the gaps—a small portion of base load and a small portion of load intermediate between the parts covered by the two blocks of hydro plants. Trans MW denotes the total capacity in megawatts sent out from the particular plant to the Southern Market. Trans GWH is the accompanying energy in gigawatt-hours.

Excess hydro MW and excess hydro GWH indicate the total hydro capacity and energy, respectively, which is left unused after the dispatch and transmission routines have been completed. Demand in MW is the Northern Market capacity demand, $P_{maxT,1}$. Finally, share of Mari, as discussed above, indicates the percentage of the thermal capacity at the Mari generating center which has been dispatched into Market No. 1 during a particular month, $\gamma_{T,1}$. If hydro power is being transmitted south no Mari power can move north, as shown by a zero share for the market and zero plant factors for the Mari units in the thermal plant listing.

The printout reproduced in Figure 9-5 shows similar information for the operation of the thermal plants used to meet the load of Market No. 2, the South, and also data on the performance of the transmission system in terms of megawatts delivered. North to Mari is the amount of hydro capacity delivered to Mari, $V_{1,3}$. One may see in June, for example, that the power arriving at Mari is exactly that sent out from the MAN50B plant (as indicated in Figure 9-4), less the loss in transmission. Mari to Karachi indicates the power arriving in the Southern Market from Mari, $V_{3,2}$. Part of this power generally originates in the North and part at Mari itself. The capacity of the line from the North to Mari during this year is 170 mw, and that of the line from Mari to the South 250 mw. Thus, in June, for example, about 226 mw arrives in the South, about 162 mw originating in the North (i.e. 170 mw less losses) and 64 mw from the Mari thermal units. Mari to Lyallpur shows the capacity dispatched from Mari to the Northern Market, $V_{3,1}$, discussed above. The last line on figure 5 presents the overall System Reserve, δ_T. If the two markets are not interconnected, a separate reserve figure is shown for each individual market.

Not reproduced here is a system cost summary which the computer prints out for each year of the planning period. It shows the capital, fuel and maintenance and operation cost incurred in that year under the several assumptions about fuel prices, the value of foreign exchange and the opportunity cost of capital.

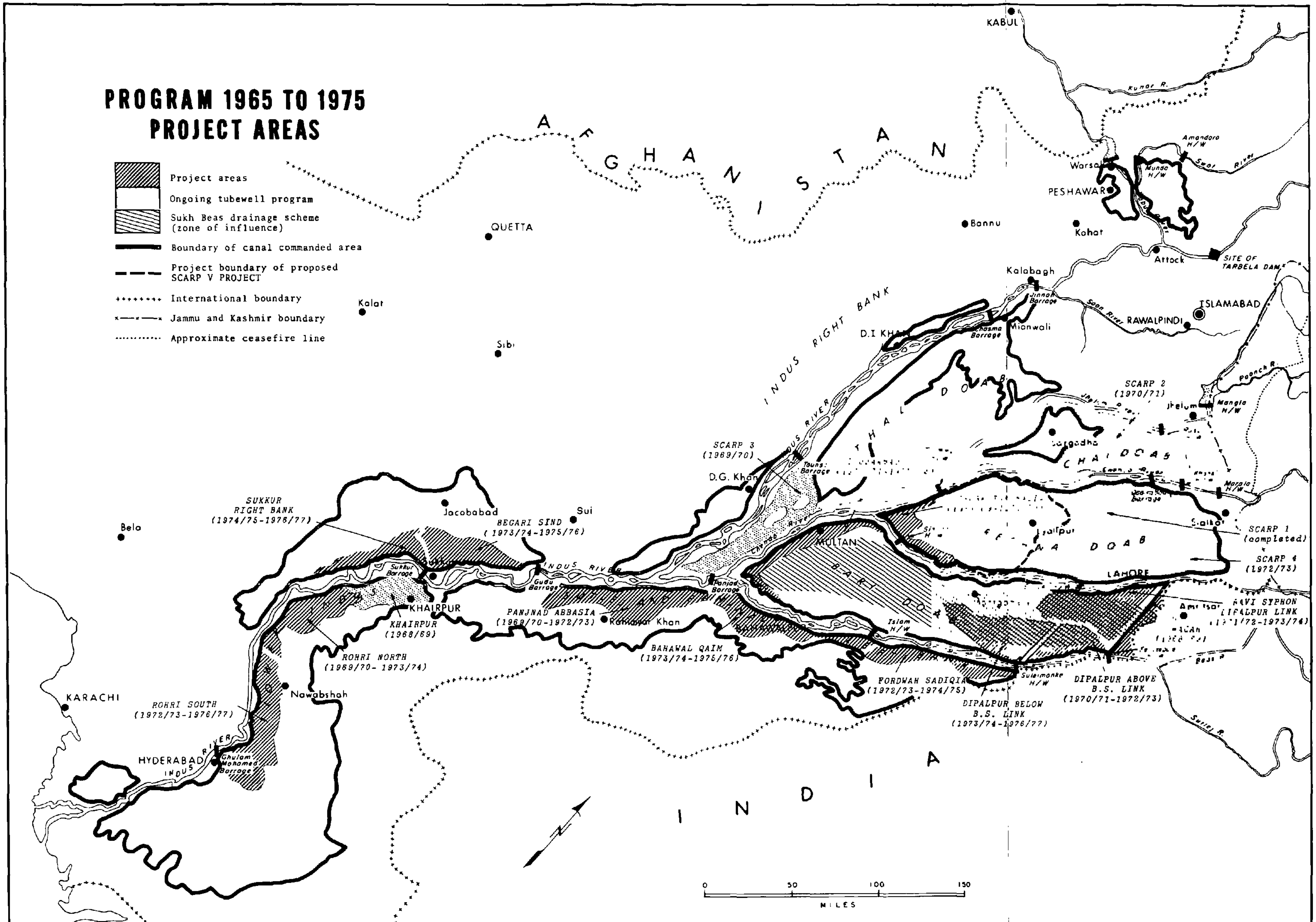
The computer printout can of course be changed with relative ease to indicate either more or less detail, as desired. The information presented in Figures 9-4 and 9-5 really represents a small sample of the numbers generated by the computer in the process of dispatching the system. These particular items were selected for printing out because of their value in indicating the essentials of the way the system was operating under any given set of conditions.

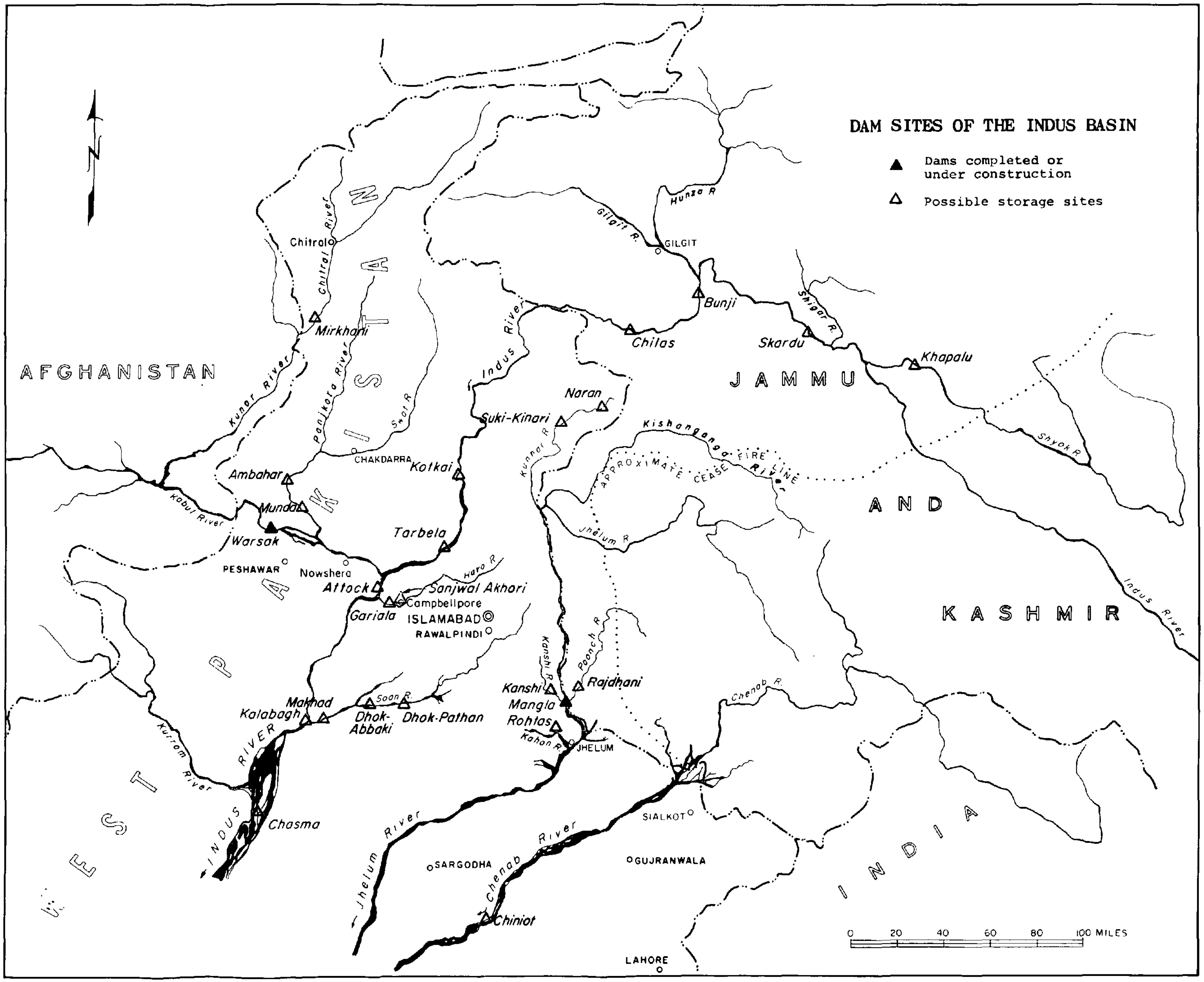
Glossary of Symbols

Symbols are presented in alphabetical order; first those constructed of standard typewriter symbols, then those based on Greek letters. Because of their mnemonic value, three characters are repeated in italic script; they are *E*, *j*, and *V*.

a_1, a_2, a_3, a_4	Parameters of the quadratic approximation to the integrated load function.
B_k	A set containing the identifying numbers of all hydro plants to be dispatched in a single block, k.
$C_j[Q_j(t)]$	Production function for thermal plant j representing fuel efficiency (BTU per kwh) as a function of instantaneous output (mw).
$\bar{C}_j$	Average fuel efficiency of plant j over the relevant range of $Q_j(t)$.
c	Index identifying different transmission systems; c = 1, . . . , *c*.
d_{oi}	Domestic component of capital cost of transmission system W_o in year i.
E_T	Total energy generated or demanded over the time interval T (mwh).
$E(P)_T$	The integrated load function; read as "the energy generated (or demanded) over the time interval T at an instantaneous system load less than or equal to P". When it is necessary to distinguish between two markets, the function may appear as $E_1(P)_T$ and $E_2(P)_T$.
$e(p)_T$	Unit or normalized form of the integrated load function.
E	Surplus hydro energy after dispatch of plants into the Northern Market.
$F(x_i, W_o)$ or $F(x_i)$	Total system fuel cost in year i.
f_j	Fuel price ($/Btu) for plant j.
f_{oi}	Foreign component of capital cost of transmission system W_o in year i.
$G(X,W_o)$	The objective function of the simulation model—to be minimized.
g	The rate of foreign exchange.
H_{jT}	Total energy available from hydro plant j over the interval T (mwh).
h_{jT}	Normalized form of H_{jT}.
i	Annual time index; i = 1, . . . , N.
j	Index identifying different plants; j = 1, . . . , *j* are thermal and nuclear units; j = *j* + 1, . . . , J are hydro plants.
i	Index identifying a dummy hydro plant used in the hydro transmission routine.
k	Index identifying hydro dispatch blocks.
$K_i(X)$	Total expenditure on capital investment in generation facilities in year i.
kw	Kilowatts.
kwh	Kilowatt-hours.
L_T	System load factor over the time interval T.
$M(x_i)$	Total maintenance and operation cost of system generation facilities in year i.
m_{oi}	Maintenance and operation cost on transmission system W_o in year i.
mw	Megawatts.
mwh	Megawatt-hours.

m_{ji}	Unit maintenance and operation cost (\$/kw) for plant j in year i.
N	Length of the planning period in years.
P	Instantaneous electric power demand (mw).
P(t)	Time path of instantaneous electric power demand.
p	Instantaneous electric power demand expressed as a percentage of the maximum demand during the period T; $0 \leq p \leq 1$. This is referred to as the "normalized" form of this variable.
P_{maxT}	Maximum value of P over the time interval T.
P_{minT}	Minimum value of P over the time interval T.
p_T	The normalized form of P_{minT}; i.e., the ratio of P_{minT} to P_{maxT}.
P_j	The upper limit of plant j as dispatched on the integrated load function.
p_j	Normalized form of P_j.
P_j	The lower limit of plant j as dispatched on the integrated load function.
p_j	Normalized form of P_j.
Q_{jT}	Output capacity of plant j (mw) in period T.
$\mathrm{Q}_j(t)$	Instantaneous load on plant j; $\mathrm{Q}_j(t) \leq \mathrm{Q}_j$.
q_{jT}	Normalized form of Q_{jT}.
R_j	Date when plant j is retired from service; $1 \leq \mathrm{R}_j \leq \mathrm{N}$.
$\mathrm{r}_1, \mathrm{r}_2$	Minimum system reserve expressed as a percentage of the amount of thermal and hydro capacity respectively.
S_j	Date when plant j is placed in service; $1 \leq \mathrm{S}_j \leq \mathrm{N}$.
T	A time interval, generally a month or a year in the calculations but often representing a day in graphical presentations.
t	Continuous time.
U_j	Denotes individual thermal and hydro projects.
$\mathrm{V}_{1,2}$	Power transmitted from Market No. 1 to Market No. 2 (mw).
$\mathrm{V}^*_{1,2}$	The constraint on transmission between Markets No. 1 and No. 2.
$\Delta\mathrm{V}_{1,2}$	An incremental block of power added to the existing transmission between Markets No. 1 and No. 2.
v	An instantaneous power level, $0 \leq v \leq \mathrm{P}_{maxT}$, used in the derivation of the integrated load function.
V	Size of incremental block of power added in each iteration of the intermarket transmission routine.
W_c	A specific transmission development plan.
x or $\lVert x_{ji} \rVert$	Matrix of zero-one variables, x_{ji}, indicating which plants are in place at various points in time. The full matrix is called a strategy.
x_i	A column vector from X indicating which plants are in place in year i.
x_N	The final column vector in X, indicating the asset structure passed on beyond the planning horizon.
$\gamma_1(\Delta\mathrm{V})$	Excess hydro energy associated with capacity $\Delta\mathrm{V}$ made available at a particular hydro plant in the Northern Market.
$\gamma_2(\Delta\mathrm{V})$	Energy required to support a dispatch of $\Delta\mathrm{V}$ into the Southern grid.
Z	Total fuel cost for the interconnected system.
α	Variable used to simplify presentation of hydro-dispatch cases.
$\Gamma(x_N, \mathrm{W}_o)$	Total terminal correction associated with the final asset structure, x_N, and transmission system, W_c.
γ_1, γ_2	Percentage of Mari capacity allocated to Markets No. 1 and No. 2 respectively.
δ_T	Market excess reserve capacity in period T (mw).
Λ	Transmission loss between Market No. 1 and Market No. 2 and between Market No. 2 and Market No. 3, expressed as a percentage of power transmitted.
π	Discount rate.
w_j	Maximum possible plant factor on plant j, expressed as percentage of the plant's rated capacity, Q_j.
Ω_j	Actual plant factor on plant j indicated by the computer program.


PROGRAM 1965 TO 1975
PROJECT AREAS
Project areas
Ongoing tubewell program
Sukh Beas drainage scheme (zone of influence)
Boundary of canal commanded area
Project boundary of proposed SCARP V PROJECT
International boundary
Jammu and Kashmir boundary
Approximate ceasefire line
AFGHANISTAN
INDIA
KABUL
PESHAWAR
QUETTA
Kalat
Sibi
Bannu
Kohat
Attock
SITE OF TARBELA DAM
Kalabagh
ISLAMABAD
RAWALPINDI
Mianwali
D.I KHAN
INDUS RIGHT BANK
THAL DOAB
SCARP 2 (1970/71)
Jhelum
Mangla H/W
Sargodha
CHAJ DOAB
SCARP 3 (1969/70)
D.G. Khan
Taunsa Barrage
MULTAN
BARI DOAB
SCARP 1 (completed)
SCARP 4 (1972/73)
LAHORE
RAVI SYPHON DIPALPUR LINK
Amritsar
SUKKUR RIGHT BANK (1974/75-1976/77)
Jacobabad
BEGARI SIND (1973/74-1975/76)
Sui
Bela
INDUS RIVER
Sukkur Barrage
Gudu Barrage
Panjnad Barrage
KHAIRPUR
KHAIRPUR (1968/69)
PANJNAD ABBASIA (1969/70-1972/73)
Rahimyar Khan
BAHAWAL QAIM (1973/74-1975/76)
Islam H/W
ROHRI NORTH (1969/70- 1973/74)
FORDWAH SADIQIA (1972/73-1974/75)
Sulemanke H/W
DIPALPUR ABOVE B.S. LINK (1970/71-1972/73)
DIPALPUR BELOW B.S. LINK (1973/74-1976/77)
KARACHI
Nawabshah
ROHRI SOUTH (1972/73-1976/77)
HYDERABAD
Ghulam Mohamed Barrage
0 50 100 150
MILES



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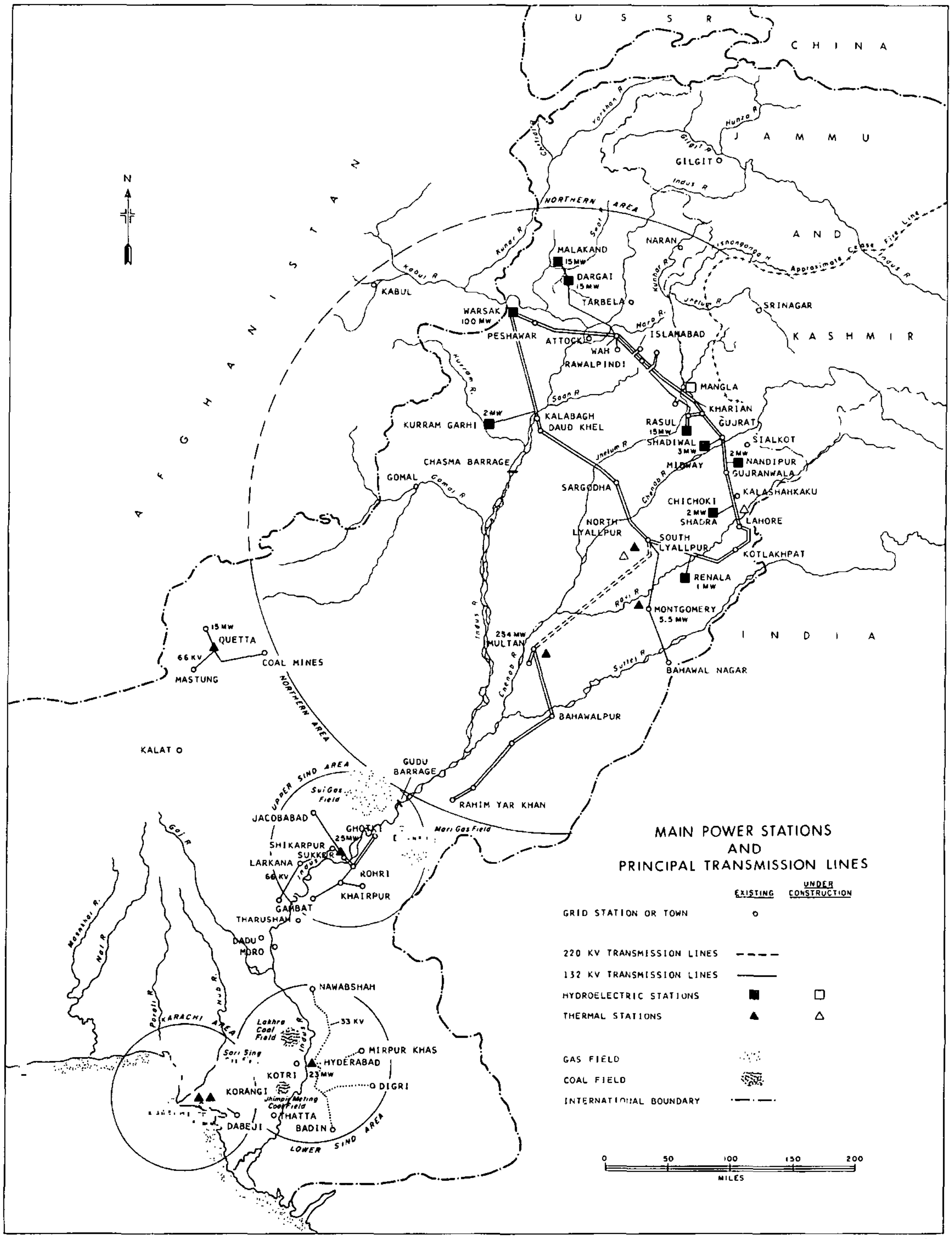

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The three volumes together represent the core of the complete report made by the Bank to the Government of Pakistan. They present not only the Study Group's conclusions and recommendations but also an invaluable record of the manner in which the problems encountered were confronted and solved, and how the Bank's consultants went about their work.

Volume I is a condensed, integrated version of the analysis and results of the entire study, including an evaluation of the huge Tarbela project, the problems of agricultural development, the interaction of agriculture with other sectors of the economy, the demand for power and means of meeting the demand, and areas of critical concern, such as the need for electrical interconnection within West Pakistan.

Volume II gives a detailed discussion of irrigation and agriculture, including the use of improved seeds, fertilizers, new cropping patterns, and modern techniques of husbandry, in addition to the development of water resources.

Volume III contains papers on the background and methodology of the study, particularly the macroeconomic framework, a linear program of irrigated agriculture in the Indus Basin, and a computer simulation of the power system.

PIETER LIEFTINCK, former Finance Minister of the Netherlands, is an Executive Director of the World Bank.
A. ROBERT SADOVE is Economic Adviser of the Bank's Projects Department.
THOMAS C. CREYKE is Adviser on Agricultural Development, Agriculture Division of the Projects Department.