INTEGRATING REGIONAL WATER AND POWER SYSTEMS

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I. Introduction*

Electric power markets grow up around centers of urban and industrial concentration, and there comes a time in the development of these systems when it is advantageous to tie together neighboring power grids by means of extra-high voltage transmission lines.

There are several reasons why interconnection so often proves to be a profitable investment. First of all, economies of scale in project construction are quite important in the generation stage of electricity supply. Furthermore, separate reserve or standby capacity is required for each independent power market. When interconnected, the reserve requirements of the integrated network usually are less than the sum of the reserves needed for independent operation.

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It also is possible to attain a more efficient overall performance of any given set of generating facilities. By the means of energy transfers over a multi-market connection, full use may be made of newer and more efficient thermal plants while less economical units are held in reserve or are used to serve peak demands. Market integration can allow much more effective utilization of hydroelectric sources as well. Rainfall and stream flow patterns may differ among interconnected regions, and better use can be made of available water by trading energy back and forth between markets from season to season or year to year. Surplus energy periodically available in one system may be utilized by another either to serve its demand directly or to pump water into storage reservoirs.

Finally, the timing of daily power requirements may vary between systems because the mix of industrial and residential power demands may not be the same or because markets may be located in different time zones. Thus the peak demand on an integrated system may be less than the sum of the separate peaks on its component markets, i.e., there may exist some "load diversity" among systems. It becomes possible to meet capacity demand in the overall grid with a smaller amount of installed generating capacity than would be required to serve the individual markets separately.

As systems expand and become integrated, however, the planning task becomes more and more complicated. Operating and investment decisions within any one market or region must be coordinated with the management of the electric power network as a whole. The attainment in practice of the potential savings from interconnection requires careful design and scheduling of new generating facilities in each of the regions, tight coordination of the operation policies followed by the respective sub-system managers, and the maintenance of a set of energy prices which provide adequate incentives for the movement of energy around the system.

Additional complexity is encountered when the operation of an inter-regional electric grid affects the management of other parts of the economy - as is the case when the system is fed by hydroelectric power from multi-purpose water resource developments.

Even with centralized ownership and control of electric systems the planning of such an interconnected network presents a considerable analytical problem. If the interconnection serves a set of autonomous regional authorities, all these matters of investment selection and system operation become the subject of inter-regional bargaining, and planning calculations must serve the additional function of informing these negotiations.

This paper presents a new analytical model which can be used to support decisions on investment selection, operating policy and pricing arrangements in situations of this type. The model has been prepared for application to a proposed interconnection of four independent regional power utilities in Colombia. The revised approach is based upon digital computer simulation of the long-run capacity expansion and short-run operation of electric power systems.[1]

2. Regional Integration in Colombia

2.1 The Proposed Interconnection

The three major cities of Colombia - Bogotá, Medellín and Cali - are located about 200 to 300 kilometers apart as shown in Figure 1. Yet due to the mountainous terrain of the country, these regional centers have developed in relative isolation from one another. The capital city of Bogotá, for example, is located at an altitude of 8,000 feet, and to travel overland to Medellín one must descend to and cross the Magdalena River at about 600 feet above sea level and then climb over a 12,000 foot mountain pass before dropping into Medellín at about 5500 feet. It should be noted that these same mountains which render transportation so difficult are a source of great wealth in water resources. Much

[1]The Colombian planning model is the latest and most complex version of an analytical technique developed originally in the context of an Argentine problem [7] and subsequently applied to a study of water and power in West Pakistan [5] [7] [8].

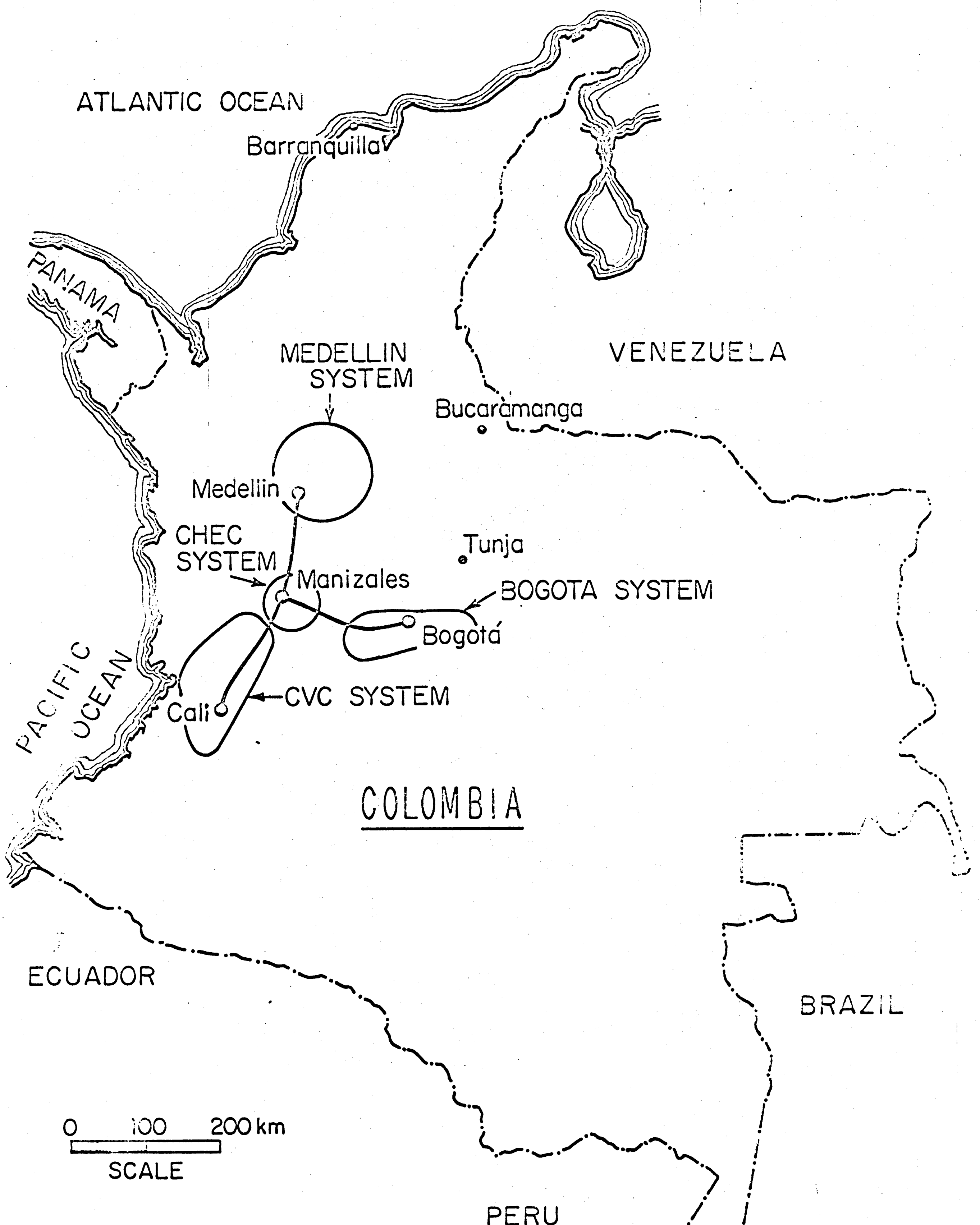

FIGURE 1.

PROPOSED INTERCONNECTION

of the high mountain area receives tropical rainfall; Colombia is one of the world's richest countries in potential hydroelectric power development.

Because of their relative isolation, each of the major regional centers has developed its own economic base, regional institutions and personality. The management of water and power resources in each area is under the effective control of a set of distinct regional and municipal authorities. In the capital city of Bogotá, electric power is provided by a municipally owned electric utility (Energía Eléctrica de Bogotá), while municipal water supply and waste disposal as well as irrigation in the Bogotá region are the responsibility of other municipal and regional institutions.

In Medellín all electric power, water supply and waste disposal and even the local telephone utility are run by a single municipal authority (Empresas Públicas de Medellín). The city of Cali is located in the Cauca Valley, and the overall development of the resources of the region is the responsibility of a river valley authority (Corporación Autónomo Regional del Cauca) patterned after the TVA and commonly referred to as the CVC. There also is a small company in the area which provides hydroelectric generating facilities serving the city of Cali while the electric energy distribution within the City itself is handled by a municipal public utility. For purposes of this discussion the various companies which serve Cali and the Cauca Valley will be denoted as the "CVC system".

Over the past ten years considerable study has been devoted to a possible interconnection of these markets [2] [3] [6]. Under the current plan a fourth city, Manizales, would be included in the inter-regional grid. Manizales is served by a local electric utility called CHEC (Central Hidroeléctrica de Caldas, S.A.) which is a subsidiary of a federal water and power agency which controls the electricity supply in many small power markets throughout the Country.

As shown in schematic form on Figure 1, the electrical interconnection would be in the form of a "T" with one of the major cities at each of the extremities and Manizales near the central connection point. The three major markets are of roughly equivalent size; Bogotá and Medellín both had peak demands of around 300 MW (megawatts) in 1967 while the peak in the CVC system was about 240 MW. The demand in Manizales at this time is about 75 MW. The Medellín and Manizales grids are served entirely by hydroelectric generation facilities; both the Bogota and CVC systems contain some thermal generation although they also rely primarily on hydroelectric sources of supply.

In preparation for the financing, construction and operation of the proposed transmission lines, the interested parties have formed an interconnection corporation (Interconexión Eléctrica, S.A.) which will own and operate all joint facilities. All the stock in the new corporation will be held by the four utilities described above, and the managers of these utilities form the board of directors of the new servant institution. The board, in turn, will appoint a manager for the interconnection company itself.

After constructing the inter-market transmission lines, the new entity will serve as a wholesaler and shipper for energy sales among the four markets. It also will build and operate all new generation facilities after completion of those now under construction or in advanced stages of planning by the individual utilities. The agreement which establishes the new corporation also covers various aspects of system operation, financing and price policy, but the details of these arrangements are beyond the scope of this paper.

2.2 Problems Presented by Regional Integration

There are significant barriers - both economic and political - to the establishment of an efficient inter-market transmission network when independent regional or municipal authorities control the different market systems. It has required several years work and negotiation to set up the interconnection company itself. But this is just the first step. A host of investment and operating decisions remain to be made within the framework of the new agreement, and these choices require a careful balancing of the various regional interests over against the broader national concern for the efficient operation of the electric power sector as a whole.

First, decisions must be made on the location, technology and scale of new generation projects. Often there is strong regional conflict over the choice of new facilities, particularly when water resource developments are at stake. If large projects are to be built in order to take advantage of economies of scale, then each new project choice involves one region getting the new facilities and the others not. The larger the project the longer the some regions must wait before they can host a major physical development. Thus when there is regional rivalry it may be difficult to reach agreement on a sequence of investments which satisfies the requirement for regional equity while providing economies for the whole.

This difficulty is magnified when electric power is generated by multi-purpose water resource developments. In effect, the interconnection renders most of the water resource planning in each region interdependent with actions taken in all the other regions. For example, approximately 85% of the electricity supply for Bogotá comes from the Bogotá River. But the River also is the sole source of water supply for this city of over two million people, and it serves as the primary municipal waste discharge facility. With interconnection, the management of the Bogotá River will be intimately related to the operation of the larger system and thereby to actions taken in Medellín, Cali and Manizales.

Likewise, most of the proposed new hydro developments in the Cauca Valley involve irrigation and flood control as well as electric power generation. Still other proposed projects are tied to major navigation schemes. Thus the new interconnection authority faces a real challenge. It is not simply a matter of regional competition for electric generating facilities; very real regional economic interests are involved in gaining the complementary outputs of physical facilities which will be justified and financed primarily on the basis of electric power production.

A further difficulty arises in the conflict over pricing agreements and short-run operating policies. If the different regional electric utilities are under independent management, then large sales of energy between markets can involve significant transfers of money. Thus the structure of energy prices, which has a great influence on the operating efficiency of the system as a whole, also must be viewed from the standpoint of its impact on the internal financial positions of the participating parties.

Little need be said about the importance of making the best possible decisions about investments, operating policies and pricing arrangements in this type of situation - particularly in a less-developed country. These social overhead facilities take a large slice out of available capital investment, and there is a considerable potential benefit to the country as a whole from an effective planning effort and a delicate balancing of these diverse regional interests. It is no longer sufficient, however, to conduct separate analyses of the water resources of the different regions. Partial analyses of individual projects considered apart from the overall system may lead to costly choices, and the desire to inform the process of inter-regional bargaining and decision making leads to the formulation of a model which encompasses the four-region interconnection as a whole.

This approach to planning is a departure from the way in which problems of this type normally have been handled in less-developed countries. The scope of analysis has not been so broad in the past, and for good reason. The detailed analysis of a complex, interdependent water and power network, if it had to be done with desk calculators and slide rules, would have required an intolerable expenditure of time as well as scarce engineering talent. Engineering consultants and planning bodies have had to be satisfied with a judicious combination of partial analyses with only loose links between the various sub-parts of the broader study.

By the same token, it has not been feasible to investigate the implications of uncertainty about certain basic economic parameters or about errors in demand forecasts. To repeat the calculations on the basis of a range of values for exchange rates and fuel prices and alternative assumptions about demand growth would have been out of the question.

With digital computers becoming ever more widely available, this need no longer be the case. If a model can be formulated which captures the essential characteristics of the system as they impinge on major planning decisions, then repetition of the calculations under a variety of assumptions is no problem; it is precisely the kind of situation where electronic computation facilities prove their worth. Given the large expenditures which a country like Colombia will be making in electric power facilities and the potential savings which might be realized by more efficient investment and management policies, the responsible authorities can hardly afford not to make use of improved analytical methods.

Once having argued that here is a great potential for application of computer models in studying this type of problem, a word of caution is in order. Computer analysis can require considerable amounts of time and talent, and it is important to be clear about the purpose of this kind of activity. Presumably the objective is to serve the decision process in each instance, and this requires a model which can be formulated and solved within a reasonable amount of time. Furthermore, the model should yield results which can be understood and used by those who actually make investment and operation decisions.

What follows is a description of an attempt to construct a model along these lines for use by the new Colombian interconnection corporation and by national planning officials. The primary focus is on long-run planning of investments, although as noted above, investment planning requires consideration of short-run operating policies, pricing and financial arrangements. First, the overall approach to the problem and the structure of the planning model are discussed. There follows a brief description of the computer program itself, the data required, and the information presented for each power system analysis.

3. Formulation of an Inter-regional Planning Model

3.1 Analysis by System Simulation

The planning method presented here involves the use of digital computer simulation as a tool for analyzing potential investment in generation facilities in each of several electric power markets, for evaluating transmission connections among markets, and for studying alternative schemes for operating such an interdependent system. Because it is no longer possible to conduct an adequate analysis of each market or new project separately, an attempt is made to construct a model which captures the essential operating characteristics of the interconnected system as a whole.

The analysis begins with a projection of electric power demand in each of the markets to be considered. In addition to demand forecasts, information is required on the capacity, efficiency, fuel price, maintenance and operation expenditure, and capital cost of each existing and potential thermal and nuclear generating facility. Similarly, the capital and maintenance and operation costs of existing and potential hydroelectric developments are needed along with monthly patterns of capacity and energy output. For every proposed inter-market connection scheme, data are required on the carrying capacities of each of the transmission links in each year along with appropriate cost information. Finally, the model requires ranges of values for certain economic parameters such as fuel prices, discount rates, foreign exchange rates and opportunity costs of capital.

Alternative electric power investment programs are defined which are "equivalent" in that each will meet projected demand growth in all markets with an acceptable standard of service quality. For any investment plan there may be several alternative operating schemes which might be followed. The computer program is used to calculate indicators of the relative economic attractiveness of each combination of investment plan and operating policy and to prepare data on the financial impact of the particular scheme on each of the regional authorities.

The evaluation of each alternative is accomplished by means of a two-part procedure. First, a detailed simulation of system expansion and operation is conducted over some planning period, say ten to twenty years. Because of the strong interdependence between the various units which are found on the system at any point in time, an approximation of the results of hourly and daily scheduling of generating units must be calculated in order to estimate the fuel costs incurred in each month of the planning period. The computer program then combines these fuel cost data with the capital and maintenance and operation expenditures implied by a particular investment schedule to produce a figure for the present value of total system supply cost over the period of analysis. This simulation of the results of daily system operation is also the source of information on the magnitude and timing of the transfers of power among the different regions.

The second part of the procedure involves an adjustment for the impact of different investment programs on system cost in the years beyond the planning horizon through the use of a simple terminal correction. The "plan period" is that portion of the future which is simulated in detail, and at the end of this period there will be a collection of assets which is passed on beyond the horizon. The form of the final asset structure will differ according to the particular investment pattern being analyzed, and this difference will be reflected in variation in the cost to serve system electric demand in the years of the more distant future. The impact of differing terminal conditions is approximated by a set of simple functions, and the computer results are adjusted to account for these effects.

Once the model has been formulated and programmed and the initial data gathered, it is possible to analyze a large number of alternative investment schemes and operating policies with relative ease and in a short amount of time. Each simulation analysis can provide a full range of information for sensitivity testing of critical assumptions, and the model can be updated to take account of changing conditions so that it can become a permanent part of the year to year planning effort.

3.2 Equivalent Alternative Investment Plans

In order to describe how equivalent alternative plans are defined let the subscript i serve as an annual time index, $i = 1,\ldots,N$, where N is the length of the planning period. And let the subscript t be used as a monthly time index, $t=1,\ldots,12$. The analysis is conducted on a monthly basis because of seasonal variation in demand and in the capability and energy outputs of most hydroelectric projects.

The main element in the demand forecast is a projection of peak loads, P_{it}, for each month of the planning period. System load is exogeneous to the model, and the load forecast is introduced in the form of a set of constraints. All valid investment plans must provide sufficient generation and transmission capacity to serve projected demand, P_{it}, with a certain minimum amount of technical reserve. Plans meeting these requirements are "equivalent" in that each will meet the minimum prescribed standard of service quality. It is, of course, possible to repeat the analysis under alternative demand projections in order to investigate the impact of forecast errors or to study the effects of policy measures which might be used to restrict or promote demand growth.

To facilitate the exposition, let the formulation of this set of constraints be introduced in the context of a single isolated market rather than in terms of the more complex four-market grid. Suppose there are a number of generating units, U_j, $j=1,\ldots,J$, which might be in service during some particular year where $j=1,...,\underline{j}$ are existing and potential thermal and nuclear units and $j=\underline{j}+1,...,J$ 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, for purposes of defining alternative system expansion plans; plant output capability is assumed constant over the year.

The output characteristics of each hydro plant are represented by its capacity, Q_{jit}, and the associated energy, H_{jit}, in each month of the planning period. Since the monthly pattern of energy and capacity available from a hydroelectric project depends on the size of the dam and on the reservoir operation policy followed, a separate project must be defined for each combination of physical design and water release schedule which it is desired to evaluate.

It is at this point that multi-purpose aspects of water resource projects enter the analysis. Each set of values for capacity and energy outputs over time, Q_{jit} and H_{jit}, for a particular physical development, j, is the result of a separate simulation of the water project itself and will reflect the impact of conflicting uses for project water. In order to explore the trade-off between the contribution of a particular facility to the electric power grid and to other water uses, a number of mutually exclusive alternative projects may be formulated, each differing from the others in the reservoir release policy being followed.[2]

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 plant U_j is in 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.

$$0 \le \delta_{it} = \sum_{j=1}^{\underline{j}} \frac{Q_j \, x_{ji}}{1+r_1} + \sum_{j=\underline{j}+1}^{J} \frac{Q_{jit} x_{ji}}{1+r_2} - P_{it} \quad (1)$$

The percentages of technical reserve capacity required for thermal and hydro units are shown as r_1 and r_2 respectively. The term δ_{it} indicates the excess reserve on the system in month t of year i, and it must not be negative for any month else the investment program be ruled invalid. Such a program for the development of generating facilities is termed a "generation plan" in the terminology of this simulation

[2]For an example of the application of this particular approach, see [5] [7] [8].

approach, and each plan may be denoted by a matrix of zeros and ones, $X = \| x_{ji} \|$; $j=1,\ldots,J$; $i=1,\ldots,N$. The particular combination of plants in existence in any year is indicated by the appropriate column vector, $\underline{x}_i = [x_{1i},\ldots,x_{Ji}]$.

For an analysis involving several markets, there is a constraint of the form of Equation 1 for each month during which a market remains an independent sub-system. When two or more markets are interconnected, there is a revised version of the constraint which must be satisfied for the interconnected pool as a whole, taking into consideration the capacities of the inter-market transmission lines. Because of the complexity of the algebra, the precise formulations of these constraints for a two, three or four market system are omitted here.

So far as the computer analysis is concerned, each plan is introduced in the form of two vectors which indicate the dates when each of the planned system additions or retirements is to be made. $\bar{S}_j$ 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 $1 \leq S_j \leq N$. $\bar{R}_j$ 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 plan period, $1 \leq R_j \leq N$.

In dealing with a multi-market system in practice, some trial-and error may be required to produce a suitable set of equivalent alternative system plans as defined by the capacity constraints. This is because it may not be possible to foresee exactly how a set of several generating facilities located in different regions will perform when managed as a system under some particular operating policy. Thus of any given number of plans, X, which are chosen for analysis initially, some very likely will have to be thrown out or modified on the basis of information provided by the simulation analysis itself.

3.3 Total System Cost

Each power development plan which meets the constraints identified in Equation 1 has an associated time pattern of capital costs, maintenance and operation expenditures and fuel costs for each market considered. In the Colombian case there are four markets, k=1,..., 4, to be served by one of several inter-market transmission systems, T. A major purpose of the planning model is to calculate the value of the objective function, G(X,T), the present worth of total system cost. This function is evaluated for various combinations of generation plan, X, transmission scheme, T, and operating policy where

$$G(X, T) = \sum_i \left\{ [1+\pi]^{-i} \, [K_i(X, T) + M(\underline{x}_i, T) + \sum_t \sum_k F_k(\underline{x}_i, T)] \right\} - (1+\pi)^{-N} \, \Gamma(\underline{x}_N, T), \quad (2)$$

$$i=1,\ldots,N;$$

$$t=1,\ldots,12;$$

$$k=1,\ldots,4.$$

The terms in the first set of brackets are the appropriate discount factor multiplied by the sum of the capital, maintenance and operation and fuel costs associated with the particular generation plan and transmission scheme. The last term in the equation is the terminal correction. The function of the computer model is to simulate the long-run operation of the power program described by a particular choice of (X,T) and to calculate in detail the costs incurred in each month and year of the interval $i = 1,\ldots,N$.

The cost function as represented by Equation 2 involves consideration of market demand patterns, plant characteristics, investment decisions and short-run system operation rules. The term $K_i(X,T)$ represents the construction cost of new facilities. The capital expenditure on any particular plant may be spread over several years, and the cost incurred in a particular year depends on the date of the start of construction. The capital cost may be broken down into domestic and foreign components if desired.

The second term in Equation 2, $M(\underline{x}_i, T)$, represents plant maintenance and operation. For any year, these costs are simply summed over all facilities in existence.

The last element of system supply cost within each year of the planning period is the sum of the expenditures on fuel during each month in each market, $F_k(\underline{x}_i, T)$. The evaluation of this term for any month requires the simulation of system short-run operation, and this is the most valuable aspect of the computer model as well as the source of most of its analytical complexity. As noted above, 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 the particular operating rules used to determine how much of the capacity of each available generating unit is used to meet the total system demand and how much power is being transmitted between markets at each instant during the interval. It is necessary to approximate the results of the instantaneous, hourly and daily scheduling or "dispatching" of the component units of the system supply structure.[3]

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[3] Additional background information on the operation of electric power networks may be found in any one of a number of standard texts [1] [9] [10] and in the publications of the various professional societies [4].

In order to evaluate $F_k(\underline{x}_i, T)$ for purposes of long-run planning, one desires a method of analysis which can capture those system operating characteristics which are of economic significance without requiring excessive computation expense. The model should represent system interdependency, but only to the level of detail necessary to make wise use of available data and to draw out those aspects of system short-run operating characteristics which affect the particular decisions under study.

In this model, the system energy calculation is based on a monthly numerical approximation of the results of optimal load dispatching. Each month the scheduling of the generating units within each of the four markets and the operation of the inter-market transmission system are simulated in order to determine the power contribution of each individual plant and the loading of each transmission line. The energy transfers between markets will differ according to the particular operating policy assumed to be in effect.

On the one hand, if it is assumed that none of the individual utilities will buy power from the interconnected system in excess of the quantities absolutely necessary to cover deficits in the local supply, then one operating pattern will result. Such might be the case, for example, if the price of energy sold over the interconnection were set too high. If, on the other hand, it were assumed that the price of excess hydro energy within any particular market was always set low enough to make it attractive to other markets to purchase the energy in order to displace generation by local thermal plants, then the system operation would be quite different. The overall supply cost would differ and the financial transfers among the four utilities would vary.

Full description of this procedure, which makes extensive use of market integrated load functions, is beyond the scope of this paper; it is presented in [5] and the complete derivation of the method is available in [7]. It should be said, however, that this numerical technique yields a close approximation to actual system operation. It also is possible to check these estimates of system fuel expenditure against actual market operating records and to adjust the calculation so as to improve the accuracy of the analysis.

At the end of N years analyzed by the model of Equation 1 and the first part of Equation 2, there is a structure of assets which is passed on beyond the horizon into what might be called the "N+ period". The composition of the system at the horizon is indicated by the final column vector of the generation plan matrix, $\underline{x}_N = [x_{1N},\ldots,x_{jN},\ldots, x_{JN}]$. and by the particular transmission scheme in place, T. An attempt is made to isolate those differences in the characteristics of the $(\underline{x}_N, T)$ associated with different plans which are likely to have a significant influence on system cost in the N+ 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 full impact of these differences among power programs during the planning period is reflected in the simulation analysis itself; the influence of different programs on succeeding years is captured by means of a set of simple continuous functions which are combined into a single cost adjustment, referred to here as a terminal correction, $\Gamma(\underline{x}_N, T)$. If an appropriate correction is not made, this fixed horizon model will bias selection against long lived and capital intensive alternatives and in favor of retaining old generating equipment on the system.

The simulation over a plan period is necessary in order to caputre the interdependence which characterizes electric power systems. It was stated above that one should build complexity into the model of daily system operation only insofar as necessary to capture the impact of these short-run system characteristics on the decisions under study. By the same token, one should simulate only as many years of system expansion and operation as are necessary to capture the interdependence among decisions at different points in time as they affect today's choices. Simulation computations can be expensive, and one should carry this detailed calculation only to the point where it is possible to capture in a set of simpler functions the essential aspects of the future as they impinge on current decisions. For further details of this procedure, see [7].

4. Computer Simulation of the Colombian System

A digital computer simulation program has been prepared for the Bogotá-Medellín-CVC-Manizales interconnected grid. The program was prepared originally on an IBM-7094 computer; it is now being revised so it may be solved on the largest and most flexible machine currently available in Colombia, an IBM-1620. In the 1620 version it can handle a planning period of twelve years. In any one computation run up to twenty existing and potential hydroelectric plants may be considered along with a maximum of ten thermal plants and two alternative transmission plans.

Given the input data described briefly above, the computer model is designed to provide the information necessary to allow comparison of alternative patterns of system capacity expansion and operation over the planning period. For each plan analyzed, several types of detailed information prove useful. Of particular interest are data on the load dispatching for each month in each of the markets and on the operation of the transmission system for they help the analyst to get a feel for the internal workings of the system under the operating rules assumed. There also is an annual system cost summary which may be printed out for each year of the planning period.

The final result of each simulation run is an economic summary of the plan as a whole; it is presented as an array of numbers representing the discounted present worth of the total cost of the program over the planning period under the various assumptions about economic parameters. With the application of a terminal correction these figures become values of $G(X,.T)$ as presented in Equation 2.

Test computations have been made with the Colombia model; its full application is yet to come. It is expected that the model will be used by the new interconnection company and by the national planning directorate to study the national and regional impacts of future investment plans, operating policies and pricing agreements. It also may be used, if desired, to verify the economic attractiveness of the interconnection itself. And it is possible that additional sub-routines may be added to the model by the interconnection company or by the individual utilities so it may be used to calculate more complete data for financial planning.

Once the model has proved its usefulness in the Colombian context - and previous experience with this approach in other situations indicates that it will - it is hoped that it will be continually improved and used and thereby aid the water and power sectors to make their most effective contribution to the economic developments of Colombia.

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