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A NETWORK PLANNING MODEL FOR POWER TRANSMISSION SYSTEM:

A SUGGESTED MODULE FOR WASP PROGRAMME

by

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A NETWORK PLANNING MODEL FOR POWER TRANSMISSION SYSTEM: A SUGGESTED MODULE FOR WASP PROGRAMME

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SUMMARY

This paper explores the possibility of improving the utility of the well-known WASP computer package for investment planning in power systems by introducing a Network Planning Model for representing and planning the power transmission network expansion in the WASP package as a module. The Network Planning Model formulation for power generation and transmission system planning is described in detail illustrated by an application for the Northern regional power network in India. The integration of the Network planning model with the existing WASP modules at various levels is suggested and the additional data input on the locational aspects of the generating plants and the topology of the transmission network is specified. The implementation of the Network planning module within the WASP package is expected to provide a capability for simulteneous optimization of the generation and transmission system expansion to the WASP model.

1 INTRODUCTION

The Wien Automatic System Planning [11,12] package (WASP) was developed at the International Atomic Energy Agency (IAEA), Vienna, to satisfy the need for an appropriate power system planning model for carrying out the Market Survey for Nuclear Power in the developing countries during 1971-72. It is based on the System Analysis Generation Expansion (SAGE) programme developed earlier at the Tennessee Valley Authority (TVA), USA. The WASP package uses a probabilistic simulation method [2,4,5,13] in the MERSIM module for simulating a large number of feasible configurations for generation expansion while considering the effect of forced outage and maintenance of units and computes for each configuration the hours of operation of each plant, operating costs and reliability of the generating system. It then uses a dyanmic programming algorithm to determine the least-cost generation expansion programme. The WASP package uses a modular concept for user flexibility and better man-machine interaction. It is divided into six programme modules which can be run individually or simultaneously in a sequence: (1) Load Description Module (LOADSY), (2) Fixed System Description Module (FIXSYS), (3) Variable System Description Module (VARSYS), (4) Expansion Configuration Generator Module (CONGEN), (5) Probabilistic Simulation Module (MERSIM), and (6) Dynamic Programming Optimization Module (DYNPRO). The individual modules of WASP and their functions are discussed briefly in Annexure 1.

WASP package is one of the most sophisticated computer models available for analysing power system expansion planning. It can accommodate a large number of generating plants of different types and of discrete plant capacities in the expansion programme. WASP uses a Fourier series expansion to obtain an accurate representation of the load duration curve from a polynomial of fifth degree fitted to load data as compared to a step function used in many other computer models. It also simulates the outages of individual plants along with planned maintenance of individual generating units and their effect on the system production cost, a feature which very few of the power system optimization models provide. Probabilistic treatment of different hydrological conditions adds another dimension to the realistic treatment of the power system planning problem by the WASP model. The effect of lower availability from the hydroplant during a dry year on the operation of the thermal plants and the production costs are shown quite clearly in the WASP output.

Though the WASP model is quite detailed in its representation of the generating system it has a few inherent limitations due to the nature of the model formulation which raises questions regarding the applicability of WASP in solving a realistic power system planning problem. Probably the most serious limitation of WASP is its representation of the power system as a single-node model by its omission of the transmission network and the related power and energy losses. The locational factor in the choice between alternative generating plants for power system expansion is also neglected in the problem formulation. WASP does not consider the problem of transmission capacity planning. In the application of WASP model for power system planning, IAEA uses auxiliary programmes for load flow/transient stability studies. But, essentially WASP model considers the total power system including the generating plants and the load centres to be located at the same place and solves the problem of optimal expansion of generating capacity for meeting the growth in demand at minimum present worth cost during a given planning horizon.

WASP is thus ideally suitable for a small power system without wide regional dispersion of generating plants and load centres. It implicitly assumes either that the location of different power plants are already decided and there are no cost variations due to alternative locations for the same power plants, or that planning the expansion of generating plant capacity is independent from the problem of transmission capacity planning and choice of alternative locations for power plants. Neither of these assumptions are realistic for an interconnected power system of reasonable size.

During the market survey for nuclear power in developing countries with largely dispersed generating and load centres, e.g., Mexico, to overcome this limitation, the country was divided into several regions and separate WASP studies were carried out for each region with the implicit assumption that each region would be self-sufficient in power. In countries like India, major regional grids connect power plants and load centres some 1,000 miles apart and concentrated location of hydro sites and coal mines in certain parts of the country makes it imperative that power transfers over large distances are considered. In such integrated power networks which are spatially dispersed, WASP model application may not be advisable as the locational aspects of the generation expansion and the planning for the transmission network could not be analysed.

As locational decisions are important in spatially dispersed systems and optimal generation system expansion and transmission system expansion are dependent on each other, neglect of the transmission planning problem by WASP is a serious limitation. Shiralkar and Parikh [15] show that alternative locations for a nuclear plant would result in large differences in costs of investment and system losses in the optimal transmission network associated with each location of the nuclear plant. To remove this, the WASP programme should be modified by including a transmission planning module which will make the model a more realistic one for application in developing countries with reasonably large and dispersed power systems. The present paper discusses a network planning model for power generation and transmission systems and suggests a network planning module which could be integrated with other modules of WASP to provide a reasonable transmission planning capability within WASP. Due to the nature of the probabilistic simulation (MERSIM) module and information flow used in WASP, multi-node representation of the power generation system and transmission system planning problem is difficult unless major revisions are carried out in the programme structure. A multi-node representation of the WASP programme might also increase the computer efforts required for problem solution to a prohibitively high level. In addition to demand satisfaction at each load centre following probabilistic simulation, cost minimization of the whole power system, including generating plants and transmission system would be required from such a model. However, some transmission planning capability can be introduced into the WASP package without increasing the size of the programme or the solution time by substantial amounts.

At the initial stage, it might be possible to ensure that the generation system configurations generated by CONGEN are feasible in meeting the peak demand at all load centres of the power system considering capacity limitations of the existing transmission network and planned expansions selected by the NETRAN module from the alternative provided by the VARSYS module. This makes a simplified assumption that if the transmission system is capable of carrying the power flow due to peak demand during the critical period, it will be feasible during other periods of the year. Alternatively, NETRAN might also look into the feasibility of transmission network during peak periods of different seasons of the year or during different hydrological conditions as the changed pattern of power flow in the transmission network might make any other period critical for transmission system design.

In the above formulation, to ensure that it is possible to meet peak demands of all load centres from the generating plants using the planned transmission system, the network model [14] described in section 3, which is based on a maximal flow or 'out-of-killer' subroutine [9], examines whether a feasible flow pattern exists in the power system network which does not violate the minimum and maximum capacity constraints on the transmission lines and the generating plants. If for any configuration during any year, the Network Model solution is not feasible indicating that a transmission system bottleneck is present, additional transmission links are added to the transmission system based on the solution of the Network Model until it becomes feasible. Only feasible generation and transmission system configurations are stored in the CONGEN output file for subsequent system simultation by the MERSIM module and optimization by the DYNPRO module.

The above formulation ensures that all power generation and transmission system configurations simulated by MERSIM module and consequently the optimal solutions selected by DYNPRO module are 'transmission system feasible' under normal circumstances not considering forced outage of generating plants and transmission lines.

As a second stage modification of the WASP model, the optimization of the transmission system expansion could be considered. Firstly, the Network model to be integrated with the WASP model could be utilized so that for each location-specific generation system configuration, only minimal cost additions are made to the transmission network. This ensures that the investment cost of transmission system expansion is minimized. The Network model could also provide an estimate of the operating cost of the transmission system including cost of power and energy losses. Along with the generation system costs computed by the MERSIM module, the transmission system investment and operating costs could be fed in the DYNPRO module to simultaneously optimize the generation and transmission system expansion.

To implement the second stage problem of including transmission planning capability in WASP, it will be necessary to modify the MERSIM and DYNPRO modules in an appropriate manner so that the investment costs due to transmission network expansion and operating costs including costs due to power and energy losses are included along with the investment and operating costs of generating plants. System costs are considered in DYNPRO module for system optimization. This formulation will simultaneously optimize the power generation and transmission system considering alternative locations of the power plants and the topology of the transmission network.

As a third stage modification it is conceived that the power generation and transmission system expansion problem could be formulated realistically as a multi-node system to actually increase the dimension of WASP. This would involve providing separate load duration curves in the LOADSY module for each load centre. The MERSIM module will have to be modified by integrating a Network model so that probabilistic system simulation is carried out in a multi-node network system following a strategy of optimal allocation of power from the generating centre nodes to the load centre nodes. It has to be ascertained whether this could be achieved without changing the existing manner of simulation and the structure of the MERSIM programme and without increasing the computational effort to a prohibitively high level. This modification should be implemented only if the resulting output from detailed simulation is useful. It appears that perhaps it would be more useful to design within WASP a capability to compute the reliability of the transmission network and the combined system reliability rather than to modify MERSIM module to achieve the proposed optimal multi-node simulation of the power system. To achieve the latter a computational scheme is needed for reliability determination in a power system network subject to failure of generating plants and transmission systems. Further research and experimentation in this area would be fruitful.

As suggested in this paper if the network model could be integrated within the WASP package at any of the recommended levels of applications discussed above, it is foreseen that the utility of the WASP programme will increase considerably. It will then be possible to apply the WASP package to analyse most of the realistic power systems available in the developing countries. The power system planning capabilities of the WASP model and the Network model are compared briefly in Section 2, following a discussion of the power system investment planning problem. The nature of the Network model is described in Section 3, initially as an independent planning tool for power system planning and subsequently as a suggested module for the WASP package. The integration of the Network planning model within the WASP package is discussed in detail in Section 4. The concluding Section 5 discusses further areas of research and suggested modifications of the WASP package to improve its computational speed and information flow between modules. The inclusion of a Network planning model as a module of the WASP package will not increase the amount of data handled by the programme substantially but additional information on the location of generating plants and the transmission system topology will be stored.

The linear version of the Network planning model using the 'out-of-killer algorithm or the nonlinear version based on an iterative algorithm [14] are both very fast computer routines. By implementing the Network model within the WASP package at only minimal additional cost due to increased data handling and computational effort, much realism could be achieved in problem formulation to make **WASP** much more valuable in dealing with power system planning problems.

2 INVESTMENT PLANNING MODELS FOR ELECTRIC POWER GENERATION AND TRANSMISSION SYSTEMS

Given an existing power system for a region containing a mix of generating plants spatially located and connected through a transmission network to load centres, and its demand growth pattern over a given planning horizon, the purpose of optimal investment planning studies is to attempt answering the following questions:

1. What combination of available technology (out of nuclear, thermal, and hydrol) should be selected for addition to the system to meet the increasing load?

2. What should be the capacity of these generating plants when different sizes are available with possible economies-of-scale?

3. Where should these new plants be located among alternative sites?

4. Which additional transmission links should be built, connecting generating centres and load centres?

5. What should be the KV-ratings of the new transmission links, and how many circuits should be used?

6. When during the planning horizon should these generating plants and transmission lines be commissioned?

An excellent survey of various approaches towards developing models for least-cost investment planning beginning with the pioneering work at Electricite' de France is given by Anderson [1]. Various approaches at optimization has been attempted including marginal analysis, simulation models, dynamic programming, linear, non-linear and mixed-integer programming [1,5,6,8,10]. The concentration in most of the studies has been towards optimal choice of type (i.e. hydro, thermal and nuclear), capacity and time-phasing of generating plants, with little or no consideration regarding the planning of the transmission networks. Thus the studies were mostly single-area studies and neglected transmission between various generating plants and between generating plants and load centres. There has been a few studies [8,10] where multi-region models were considered with transmission lines joining various regions but still neglecting transmission within the regions.

Transmission networks are explicitly considered in load-flow studies which are undertaken to determine the actual voltages and currents, the corresponding phase angles and power losses in an electrical network given certain power inputs and outputs at the various nodes. Load flow studies are useful as they simulate the behaviour of a particular power system under normal conditions and under various contingencies induced by the outage of generating plants and transmission lines, and give valuable information regarding system reliability. Load flow studies involve the solution of a set of nonlinear a-c flow equations and no optimization in terms of optimal choice of generating plants or transmission lines could be attempted through load flow studies. However, they could be useful in comparing system reliability under various contingencies of alternative power system designs where economic or least-cost studies have already been carried out.

Planning for the power generating system expansion should not be carried out in isolation from the transmission systems planning. Same generating plant located at different places in a power system could result in varying costs due to additional investments needed in agumenting the transmission network. Also transmission system bottlenecks could result in failures to meet peak demand at the load centres even when sufficient generating capacity is present. Optimal investment planning models for power systems should, therefore, have a reasonably accurate representation of the various existing and proposed generating plants, their alternative locations, if any, the existing and proposed transmission lines, the system network indicating the way load centres are connected to the generating centres, and the operation of the total system for meeting power demand at the load centres. The Network Model [14] described in Section 3 was developed to satisfy the requirements of such a model under certain simplifying assumptions regarding the operation of an electric power system.

The Network model attempts to answer the first five questions listed above while minimizing the overall system cost. Additions to generation and transmission system are planned to meet the projected demand at the end of the planning horizon with the assumption that system additions are made at appropriate times during the planning horizon to keep pace with the growing demand. In this sense the model is a static one as it does not answer the scheduling problem during the planning horizon, the last question in the above list. A dynamic model could be formulated wherein the planning horizon is divided into a number of periods and optimal scheduling of generation and transmission projects are obtained as the solution of the model. Such a dynamic model is developed by integrating the network model in a dynamic programming framework [3].

The dynamic programming approach determines the number of periods, not necessarily all equal, into which the total planning horizon should be divided and the length of each such period. The network model is applied to obtain optimal power generation and transmission system expansions needed to satisfy peak demands at the load centres at the end of each of these periods. The number of optimal periods will depend on the discount rate used in the dynamic programming-network model for computing present worth of future investments and operating costs which is the objective function to be minimized.

The main characteristics of the WASP model, which also uses a dynamic programming optimization scheme, are probabilistic simulation of the operation of generating plants for the computation of operating hours and production cost, accurate representation of the load duration curve, consideration of several hydrological conditions and pumped storage plants and a modular programme structure.

The WASP model answers questions 1 and 2 above and question 6 in the case of generating plants only, but throws no light on the other questions which must be resolved by the application of other modelling technique or through repeated loadflow studies. It concentrates its efforts in planning the generation system and provides a more accurate representation of the loading and operation of the plants including consideration of plant outage and planned maintenance. It uses a two-block representation of thermal and normal hydro plants, and following a probabilistic simulation approach estimates with reasonable accuracy the hours of operation of each plant and the system production cost for a large number of alternative generating system configurations. A novel dynamic programming scheme determines the configuration with the least present worth value of future costs.

The Network model in comparison to WASP model uses a simpler, but integrated representation of the generation and transmission system and its spatial nature. But the Network model as formulated represents the power generation and transmission system operation only during the peak period or at any other period of a particular year. By using a simple device of providing two generation arcs for each power plant it can also provide a two-block representation of a thermal generating plant with different base and peak operating costs. Similarly, by providing multiple arcs for each transmission link it can represent existing or proposed transmission lines of different KVA ratings or simulate the effect of nonlinear power loss function. The main characteristic of the Network model is that it uses information on the topology of the power system to simultaneously optimize the capacities and locations of generating plant and transmission system expansions.

The Network model is however limited as it can simulate only one load condition at a time, as compared to various linear programming and mixed-integer programming power system planning models [1,8,10] or WASP model which simulates the operation of the power system using either a discretized or a continuous load duration curve.

The WASP and Network models, if integrated together will then supplement the capabilities of each other and the resulting WASP-NETWORK modelling framework would be able to provide a more accurate representation of the power generation and transmission system than possible now with either of these models. To obtain an optimal generation and transmission system expansion plan, the integration of the Network model within the WASP model framework may be carried out in various stages, in the NETRAN and MERSIM modules. In the NETRAN module the Network model may be used to generate feasible transmission network designs which would ensure that peak demands at all load centres will be met under normal operating circumstances or under any specified failure conditions. As a second stage modification, the Network model may be used to generate optimal expansion configuration of the transmission network requiring least additional investment, corresponding to each generation expansion configuration. The resulting generation and transmission system expansion configuration will then be simulated in MERSIM first to provide the hours of operation of each plant, costs of generation and generation system reliability. The solution of the network model could also provide the costs due to operating the transmission network (mainly due to power and energy losses) which when added to the costs of generation would give the total system operation costs. The MERSIM output file data will then provide the costs due to both generation and transmission of power to the DYNPRO module which will also consider the investment costs in generating plants and transmission lines, and compute the present worth costs of all generation and transmission system expansion configurations presented to determine the optimal solution.

3 NETWORK PLANNING MODEL FOR POWER GENERATION AND TRANSMISSION SYSTEM

In this section of the paper, a Network Programming Model for least-cost investment in electric power generation and transmission systems is presented [14]. This model could be integrated with the WASP Programme as a module for planning the electric power generation and transmission system network for supplying the projected peak demand at a number of dispersed but connected load centres. The model described in this section is essentially an operations research model based on the power system network in which electric power flow from the generating nodes to the load centres through existing or proposed transmission lines is simulated and costs of generation and transmission of power including power and energy losses in the transmission network are accounted for. The model with the aid of a network computer programme obtains a least-cost flow pattern in the conceptual network and determines the optimal investments in generating plants and transmission network. The optimal solution obtained should be tested with load flow studies to determine system reliability under various contingencies as is done in case of any other modelling approach.

A power system could be easily visualized as a network consisting of a set of 'nodes' denoting spatially dispersed generating plants and load centres linked together by 'arcs' which denote the transmission lines. In the investment planning network model used for capacity expansion decisions the detailed power distribution network is not included in the model. The load centres included in the power network represent electrical substations, where transformers reduce voltage from high tension transmission lines for distribution over a large area. The load at a particular node is equal to the consumption within that area, plus the distribution losses. It should be noted that optimal distribution network design is also a network optimization problem and can be handled using similar modelling approach.

The power system network described above consisting of generating plants and load centres as nodes, and transmission lines as arcs is augmented by the addition of other fictitious or conceptual nodes and arcs for model formulation. One specific node S, called the 'source' node is added and this is connected to all generation nodes, representing existing as well as proposed generating plants by a set of conceptual arcs called the generation arcs. Similarly, another specific node T, called the 'sink' or the demand node is added and all nodes representing load centres are connected to the demand node by conceptual arcs to be called the consumption arcs. It could be conceived as if all power is being generated at the source node S and flows through the generating nodes and the transmission network to be finally consumed at the demand node T after passing through the load centres. A conceptual network representation of a hypothetical power system is shown in Figure 1.

Thus, in the augmented network, we have a generation arc, terminating in a generation node corresponding to each existing or proposed generating plants and flow in a generation arc corresponds to generation of a certain amount of power in megawatts in the generating plant.. Similarly, ocrresponding to each load centre there is a consumption arc and any flow in this arc represent the consumption of electricity at the load centre. In addition to this, each transmission line is represented by one arc joining two nodes which could be generating plants, load centres or junction points where two or more transmission lines meet. Transmission lines in which the direction of power flow is not specified and it is possible for power to flow in either direction are represented by a pair of arcs oriented in opposite directions so that model solution can choose either of the arcs to indicate the direction of power flow. By convention, all arcs in the model network are directed and flow can take place in an arc only along the orientation of the arc. The orientation of an arc is specified by the order of the nodes at its extremities and flow takes place from the initial to the terminal node.

Each arc in the model network is associated with three other parameters: lower and upper bounds on arc flow which should not be violated and unit cost of flow in the arc, being the cost of sending for one unit of time, one megawatt of power through an arc of the network. Total cost of flow through an arc could be a nonlinear function of the flow in the arc specifically for transmission arcs due to nonlinear power losses and also for generation arcs if economies-of-scale are present, but for the time being these costs are assumed to be linear. Nonlinear costs functions could be handled by solving the network model in an iterative fashion using a special network algorithm developed for this purpose which showed excellent convergence properties. The bounds of flow and unit cost of flow in specific arcs of the network are judiciously specified so that the model network gives a realistic representation of the system constraints and costs.

Each generation arc representing a generating plant has a lower bound of zero and an upper bound equal to the maximum available capacity of power generation in megawatts (MW). An unit cost of flow is also specified for each generation arc given by the cost of operating one unit (MW) of generating capacity for one hour (or any other chosen unit of time). This unit cost consistsof the variable costs due to fuel and lubricants for generating one megawatt-hour (MWh) of power and the hourly allocation of the annualised cost of plant installation and fixed maintenance costs for proposed generating plants. The hourly allocation is obtained by distributing the annualised installation cost per MW over the maximum available hours of plant operation in a year considering maintenance and forced outage. In case of proposed hydro plants, the annual hydro energy availability determines the maximum available hours. In case of existing plants, the unit arc cost consists only of the variable operating costs due to fuel and lubricants and hourly fixed maintenance costs. A two-block representation of a generating plant is possible by using two generating arcs for each plant to a represent base and peaking blocks, the latter having a higher unit cost. The base block will be loaded first as the corresponding arc has lower unit cost and the lower and upper bounds are equal to zero and the base capacity. The arc representing peaking block would have lower and upper bounds equal to zero and peaking capacity.

The consumption arcs have both lower and upper bounds equal to the peak demand and the unit cost of flow is taken as zero or a given value to reflect the cost of distribution of one MWh of power and energy losses in distribution network. Revenue for electrical energy sold could also be considered in the model by defining appropriate negative unit costs in these arcs and defining lower and upper bounds of flow as the minimum and maximum amount of power that could be sold at the load centre. The capacities of the transmission lines, based on their KVA rating, number of circuits and conductor size, determine the upper bounds of flow in the transmission arcs, the lower bound being zero. Unit costs of flow in a proposed transmission arc is set equal to the hourly allocation of the annualised installation and maintenance cost per megawatt of transmission capacity plus costs due to power and energy losses evaluated in economic terms for a power flow of one megawatt during one hour. For existing transmission lines the installation cost is not included in the unit arc cost.

The constraints of the network model and the objective or criterion function to be minimized can now be expressed by mathematical relationships for a given power system. Let there be m generating plants, n load centres and p junction nodes in the transmission network in addition to the source node S and the demand node T. We define the following notations:

f_{Sg} = Power generated by the generating plant g, in MW; $g = 1, 2, \ldots, m$.

f_{dT} = Power consumed by the load centre d, in MW; $d = 1, 2, \ldots, n$.

f_{ij} = Power flow in transmission line (i,j), where node i and node j are connected by a directed arc and each of them is either a generation node, a load centre or a junction point. $i,j \neq S$; $i,j, \neq T$.

U_{ij} = Upper bound on flow in transmission arc (i,j).

L_{ij} = Lower bound on flow in transmission arc 9i,j).

c_g = Unit cost of power generation for one hour at the generating plant g per MW, i = 1,2,......,n.

d_{ij} = Unit cost of power transmission for one hour through transmission line (i,j) per MW; $i,j \neq S$; $i,j \neq T$.

e_d = Unit cost of power consumption (including distribution cost and/or revenue earned) for one hour at the load centre d per MW; d = 1,2,....,n.

P_g = Available capacity of the generating plant g during peak period, MW.

L_d = Peak demand at the load centre d in MW.

The following constraints must be satisfied by any flow solution to the model network:

Generating capacity constraints	$0 \leq f_{Sg} \leq P$, g = 1,2,......., m	(1)
Load constraints	$L_d \leq f_{dT} \leq L_d$, d = 1,2,.....,n	(2)
Transmission capacity constraints	$0 = L_{ij} \leq f_{ij} \leq U_{ij}$; $i,j \neq S$; $i,j \neq T$	(3)

Subject to the above constraints, the objective function (TC) corresponding to the total generation and transmission cost in the network has to be minimized for satisfying the peak demand at all load centres for one hour.

$$\text{Minimize TC} = \sum_{g=1}^{m} c_g f_{Sg} + \sum_{\text{all}(i,j)} d_{ij} f_{ij} + \sum_{d=1}^{n} e_d f_{dT} \quad \ldots(4)$$

A solution of the network model expressed as a set of flows in the arcs which satisfies constraints (1) - (3) and minimizes the objective function (4) is termed as an optimal solution and represents a design of the system network. The optimal values of flows in the generation arcs denote the optimal capacities of the various generating plants, and the optimal flow distribution in the transmission network denotes the transmission network design. This is an optimal choice based on the hourly cost of operation to supply system annual peak demand from a set of existing and proposed plants at different locations and through a set of existing and proposed transmission links. As the generating plants can run at any capacity above their minimum operating capacity and below their rated installed capacity, the optimal flow solution could be used to reach a decision regarding the optimal capacity of proposed plants and retirement of existing plants. Similarly, the KV rating and number of circuits of proposed transmission lines could be determined from the optimal solution based on the flow in a transmission line.

The optimization of the network flow problem described by Equations (1) - (4) is a linear programming problem and an optimal solution can be obtained by using the Simplex method [7] for which standard computer routines are available. However, the network structure of the problem makes it amenable to a simpler and much faster network flow solution procedure described by Ford and Fulkerson [9] as the 'Out-ofKilter' algorithm. As described later, the solution procedure may have to be judiciously applied in an iterative manner if nonlinear cost functions are encountered or the optimal solution includes some generating plants and transmission lines at a very low capacity.

The Network model objective function as defined by equation (4) above minimizes the cost of operation of the generation and transmission system for one hour during the period of peak demand (or any other critical period) in the last year of the planning horizon. The cost coefficients c_g and d_{ij} are defined in such a way that while for proposed plants and transmission lines they also include hourly allocation of the installation costs, for existing generating plants and transmission lines they only include the costs of operation, mainly due to fuel used in the generating plants and energy lost in the transmission lines. Due to this flexibility, the network model could also be used as short term operational model for planning generating plant commitments. Given a set of existing generating plants spatially dispersed and connected to the load centres through a transmission network, the short term operational planning model determines the optimal loading of the generating plants and power flow pattern in the transmission network for demands at all load centres while minimizing the total cost due to power generation and transmission. Further, the network model used in this manner as an operational planning model could be utilized to study the effects of planned maintenance of plants, plant outages, and transmission line failures on the system performance and operating costs. A large number of alternative possibilities could be examined at minimal computational effort due to the extremely fast solution technique available. Used as an interactive model with a visual display of the system network,the appeal of the network model to the user and its advantages in the load despatching, maintenance planning and unit commitment functions would be considerable.

The objective function (4) of the Network model used for short term operational planning purposes does not include any allocation for the installation costs as it is used for optimal operation of plants and transmission lines already installed. If a discrtized version of the annual load duration curve is used and minimal operating costs and optimal operating schedules for a set of existing generating plants are determined for each step of the load duration curve, then from these solutions the minimal annual cost of operation of the power system and optimal operating schedules for the year could be obtained.

The Network model as formulated earlier for the solution of the medium term investment planning problem for capacity expansion of the power system does not provide the minimum cost of annual operation in the final year of the planning horizon directly as the solution of the model. The Network model essentially ensures that during the period of maximum (peak) demand for power, sufficient generating and transmission capacity is available in the system and the investments decisions are made to minimize system operating cost including the allocation of investment costs during the peak period. The alternative generating plants consisting of hydro, nuclear and thermal plants are also compared on an equivalent basis in terms of how economically they will operate during the whole year. Their capital costs, annual availability of energy in megawatt-hours, and cost of operation per megawatt-hour is taken into account in determining the optimal plant mix.

The objective function represented by equation (4) associated with the Network model for optimal investment planning could be considered as a surrogate for the more desirable objective function which would involve minimization of the annual cost of operation in the target year, including annualised capital amortisation costs and new investments. The cost coefficients for the generation arcs (c_g) and the transmission arcs (d_{ij}) are defined to include both the costs due to investment and operation for the proposed generating plants and transmission lines and if the power demand at load centres were uniform throughout the year, the minimization of the objective function (4) would have been equivalent to minimizing the annual cost of operation in the target year. Also, as the capacity and energy availability of the hydro plants are usually limited by the water level in the reservoir,and the annual storage capacity (or river discharge in case of run-of-river plants) the hourly allocation of annualized investment cost for the hydro plants in c_g

have been normalized to make one megawatt of hydro generating capacity equivalent to that for the thermal plants which are assumed to be available for operation at their full capacity at any time when they are not under planned maintenance or repair following a forced outage. Different thermal plants requiring varying periods for planned maintenance and forced outage have also been normalized similarly. The cost coefficient (c_g) of hydro, thermal or nuclear plants obtained by diving the annualised total installation cost for one megawatt capacity by the number of operating hours available in a year and adding the variable cost of generating one megawatt-hour of energy, thus represents the true cost of generating one unit of energy using any of these plants if they are utilized to their maximum available number of operating hours. Investments made in one or the other new plants for additional generating capacity in megawatts are then evaluated on an equivalent basis for meeting the system load during the peak demand hour. Due to the nature of variability of the system load, the optimal mix of generating plants though all needed during peak hour for generating energy or for providing reserve, cannot be utilized to their fullest capacity at other times. During any time of the year the plants will be operated following their economic loading order and other system constraints so that the plant having the highest operating cost will be brought into operation only when all other plants higher up in the economic merit order are already operating or they are under planned maintenance or repair.

The cost of annual operation of the generating system will thus be given by adding the annualised investment cost and fixed maintenance costs to the product of the actual hours of operation of each plant and its hourly operating cost, and summing this over all the plants. Similarly the annualised cost of transmission system investments added together to the operating costs of the transmission system including energy losses will give the annual cost of operating the transmission system. If the power system is operated in an optimal fashion using the Network model or any other model for ooperational planning, following investments made as recommended by the investment planning Network model, then the annual cost of system operation will be minimized for the given power system. The Network model applied during the peak period determines the optimal system configuration in meeting peak system demand. The annual load duration curve could be approximated by a step function and the optimal system configuration determined from the peak demand conditions used as the existing system in an operational Network model, and solved sequentially for system loads corresponding to all other steps in the load duration curve, would provide the optimal schedule of plant operations and the hours of operation of each plant during the year. The annual cost of system operation following optimal utilization of the system configuration generated by the Network investment planning model could then be easily obtained.

The investment planning problem for power system essentially is a fixed-charge type of problem due to discrete capacities in which standard-sized generating plants and transmission lines are available and ideally a mixed integer linear (or nonlinear) programming formulation [8,10] would be suitable. But the computational efforts for large sized power systems with detailed representation of generating plants and transmission network would be considerable. In the Network model the generating plants and transmission line capacities are treated as continuous variables. It is seen that for most of the generating plants in a typical solution of the Network model, either the maximum capacity of a plant is suggested or the generating plant is rejected. In case a generating plant is included inthe optimal solution at a very low capacity, an alternative plant of a lower capacity would be recommended. Similarly if certain transmission arcs are shown to have very low flow values in the optimal solution when compared to their maximal capacity for power transmission, a lower capacity transmission line could be recommended. With such adjustments a few iterations of Network model would usually provide a more realistic system configuration.

The Network model proposed here approximates the flow of electric power in a network by taking into account the First law of Kirchoff and assumes flow conservation at the arcs and nodes of the network. The power losses in the transmission network could be approximately estimated and the demands at the load centres proportionately increased.

An improved Network model is also available which takes into account the losses in the transmission arcs by using a multiplier for each such arc which approximately denotes the efficiency of power transmission in that arc. As power loss is a nonlinear function of the flow in a transmission line the multiplier estimates actual power loss with a certain degree of accuracy. If more accurate representation of the power losses is desired an iterative approach could be used in which the arc multipliers are recomputed after each Network model solution, based on the optimal flow in the transmission arc. This is the same strategy that has been successfully used to represent nonlinear cost functions in the Network model related to energy losses in the transmission arc or fuel costs in the generation arcs.

A more accurate representation of an electrical power transmission system would involve using an Electricity Network model satisfying both the First and Second laws of Kirchoff, which uses a linear approximation (d-c load flow) and considers the electrical characteristics of the various elements in the power network. Both the node-arc incidence matrix (used in the present model) and the independent cycles matrix are used in this formulation to satisfy the Kirchoff's laws. The Electricity Network model of the d-c load flow type could be formulated from the electrical characteristics of the power system elements and the topology of the network.

The Electricity Network model of the d-c load flow type is recommended if the Network model presented here results in larger errors in predicting the flow patterns in the transmission network as could be checked with nonlinear a-c load flow studies. The Electricity Network model represents the power system network as a linear system and its solution technique is the application of the well-known simplex method of linear programming [7]. The Network model presented here uses a much faster network cost minimization programme known as the 'out of Kilter' algorithm [9], and is capable of analysing very large power network problems - involving hundred of nodes and arcs with only minimal computer effort, which is one of the main attractions of this model.

The Network model for power generation and transmission system planning discussed in this section was applied for analysing the power system expansion for the Northern region grid of India to meet the system load at the end of the 5th Five Year Plan period (1978-79). For the purpose of coordinated development and operation of electric power system in India, the country is divided into five power regions. The Northern region includes the States of Jammu & Kashmir, Punjab, Haryana, Rajasthan, Uttar Pradesh, Himachal Pradesh, and Union Territory of Delhi. The power system in the Northern region is connected and the operation of the system is coordinated by the Northern Region Electricity Board, though each of the State power systems are governed by the respective State Electricity Boards. The Central Electricity Authority, the technical planning and coordinating body of the Central Government is the sanctioning authority for investments for system expansion in the States of India and they use a regional approach in planning and deciding on system expansion.

The basic data regarding the existing and proposed generating plants and transmission lines, peak demands at load centres and cost data used in the study were very similar to those used by Chakravarti et al [6] and Shiralkar and Parikh [15]. The annual peak demand for electricity at various load centres in the Northern region for the year 1978-79 is shown in Table 1. To meet the gap between the existing generating capacity and the system peak demand for 1978-79, several project proposals for new generating plants were considered. A list of existing as well as proposed generating plants, their types and capacities is shown in Table 2. The existing transmission system also needed augmentation by the addition of new links and by strengthening the existing links, wherever necessary, for carrying the increased power load and for connecting new generating stations to the load centres. Several new 400 KV lines were also proposed to interconnect major generating and load centres, to reduce the transmission losses and to improve the reliability of the system. A list of existing as well as proposed transmission lines with their KV ratings and route length in Kilometres is shown in Table 3. Only transmission lines of 132 KV, 220 KV, and 400 KV have been included in the representation of transmission system in the Network model. For transmission lines with lower KV ratings and distribution network, the demands were grouped and added to the load centre where they are connected to a transmission line of 132 KV or higher rating. The demand considered for each load centre was the annual peak demand in 1978-79, expected to occur during the working days of the week in summer months, and these demands have been augmented by certain reserve margin to account for plant failures and power losses in the transmission network. The capacity of a transmission line in megawatts is limited by its KV rating, the number of circuits and the size of the conductors. Table 4 shows the ranges assumed for transmission lines of different KV ratings as well as their capital costs, conductors sizes and the K factor values which expresses the power loss in watts per megawatt for one kilometer length.

In the network model the higher values of the ranges were used as upper bounds on the transmission arcs and lower bounds were fixed at zero. If flow in any proposed transmission arc was below the recommended range, then a transmission line of lower KV rating would be recommended unless there are other considerations such as system reliability or future demand growth to justify a transmission line of higher KV rating.

Different assumptions were made for the existing and proposed plants regarding their costs of generation as explained earlier. Thermal and hydel plants on which construction work had begun or was about to begin soon were assumed to be ready for power generation in 1978-79 and treated as existing plants. All the other plant proposals for which sanction had not been given were considered as proposed plants. Among the proposed plants a nuclear generating unit at four proposed locations, Narora, Matatila, Rupar and RAPP were considered. Subsequently Narora was chosen as the location for this plant and other locations were dropped from the model.

It was observed that in many cases more than one generating plant was located at the same place as in Obra, Kanpur, Delhi, etc. These locations were defined as generating regions and an additional node was assigned to each of these regions where generated electricity from all the plants flows in for further transmission to the load centres. Some of the generating regions and load centres were at the same location, i.e., Kanpur Delhi, etc. In these situations, separate nodes in the network were defined to represent generating regions and load centres and these were connected with high-capacity transmission arcs with zero or very low unit cost of flow in these arcs.

In case of existing generating plants the capital cost is a sunk cost and hence it is not considered. Cost of generation for existing plants include fuel cost and only 2.5% of their capital cost as annual maintenance charges. For the proposed plants, the cost of generation includes fuel cost and annual charge of 12.5% of the capital cost (this consists of 6% interest charges, 4% for depreciation and insurance and

2.5% for maintenance charges). This cost differential between existing and proposed plants will ensure that in the network model solution the existing plants will be utilized to their installed capacity before proposed plants are called in. Only in the case of old thermal plants of very low efficiency and high operating costs, the model might recommend their retirement.

The annual cost of transmission also has fixed and variable components. The fixed costs are due to annual capital charges (interest, depreciation, etc.) and the variable costs are due to power and energy losses during transmission. To counteract the power lost during transmission, additional capacity must be commissioned and the costs of this can be ascertained. Similarly, the energy losses could be priced to obtain a monetary value. Both these costs have been more or less standardized for 132 KV SC/DC, 220 KV SC/DC and 400 KV SC lines and for any line they are directly proportional to the legnth in kilometres. Again a distinction is made between existing and proposed transmission lines and no capital charges are shown against existing lines.

Given the KV rating and the number of circuits for a transmission line, the amount of power in megawatts that can be economically and safely transmitted is given by a range as described earlier. If the amount of power to be transmitted is known, then transmission costs per megawatt can be computed. Whereas the variable operating costs due to fuel costs are approximately linear for generating plants, the cost due to power and energy losses is a nonlinear function of power transmitted and is proportional to the square of power transmitted in megawatts.

The nonlinearity of the power loss function creates some difficulties in the network model for existing transmission lines. However for proposed lines though the annual cost of capital charges per megawatt (a decreasing function of the amount of power transmitted, in MW) and the annual cost of power losses per megawatt (an increasing function of the amount of power transmitted, in MW) are both nonlinear functions the resulting total cost of power transmission per megawatt was found to be reasonaly linear for a wide range near the transmission capacity of the line. Within this range, the cost of transmission for proposed lines could be taken as linear. These costs have been computed following the assumptions given below and are listed in Table 5. For existing lines an average unit cost is used for a range, in Table 5, and based on the actual power flow in the transmission line this unit cost value can be corrected in an iterative fashion.

An optimal solution of the network model specifies a distribution of power flow in the transmission network. From this data the efficiency of the transmission lines and power loss in them could be easily computed. The optimum solution could be corrected by either generating additional power at the generating nodes to counteract the power loss or agumenting demand at each load centre by the amount of power loss in transmission from the generating node and obtaining a new solution with the augmented values of demands. Thus power generated in the system could be computed in an iterative fashion to provide for the power lost in the system in addition to the demands at the load centres and this method of computation should converge quickly. An alternative way of accommodating power losses due to transmission in a network model is to use a special kind of network formulation known as 'networks with gains' discussed earlier.

From the available data on the existing and proposed generating plants existing and proposed transmission lines, capital and operating costs and demand for power at various load centres of Northern Electricity Region, the conceptual network was constructed following the procedure described earlier. The generating plants were grouped into 18 generating regions each represented by a node and the load centres were grouped into 43 nodes. There were 100 transmission lines (existing and proposed) and the conceptual network for the investment planning model consisted of 259 arcs, some of which were needed to satisfy various system constraints and characteristics of the generating and transmission system.

The network model was solved by using NETFLØW code, a version of Ford and Fulkerson's 'out-of-Kilter' algorithm in IBM 360/44 computing system and each run took approximately 1.0 - 1.5 minutes of computer time. Starting solution was provided by assigning initial flow values in all the arcs of the network which were judiciously chosen based on the knowledge of the power system and satisfying flow conservation (flow into a node = flow out) at each node of the network. Six computer runs were made as described below to systematically improve the accuracy of the model and to obtain solutions under alternative assumptions regarding the available capacity of hydro plants during system peak demand. The generation schedule obtained as solution of these runs are summarised in Table 6. One of the optimal solutions (solution No.5) obtained as a result of the study is shown in Figure 2 plotted on a diagram of the Northern Region power network. The optimal capacities of existing and generating plants and optimal values of power flows in the transmission lines are also shown in Figure 2.

In the optimal solution obtained in the first computer run, it was observed that flow in some of the arcs were outside the prescribed ranges which were used to compute the unit costs for the model. New unit arc costs were computed based on optimal flows obtained in the 1st computer run and with these augmented costs, the second computer run was made. The optimal flow solution obtained in the arcs were now within the prescribed ranges and this solution was considered satisfactory. During the first and second runs, it was assumed that all hydro plants were available for power generation at their installed capacity during the peak demand period.

In the third computer run the available capacity during peak demand period was reduced to 75% of the installed capacity for all hydro plants. In addition to this, locations of the nuclear plant at Rupar and RAPP were suppressed from further consideration as during the first two runs these locations were not used. The result of reducing available hydro capacity is an increase in the utilization of existing and proposed thermal plants and nuclear plants and an increase in total system cost.

In the fourth and fifth computer runs, the available hydro capacity was further reduced to 50% of the installed capacity. This might correspond to a dry year and indicated the additional thermal capacity that should be built in to counteract the adverse effects of a dry year. The nuclear plant locations at Narora and Matatila were compared in the fourth and fifth runs, the fourth run considered Matatila and the firth run had Narora as the location. The Narora location ensures a higher utilization of the nuclear plant with a corresponding reduction of system cost by Rs. 23 million per year.

The last run was made to increase the accuracy of the model solution and new unit transmission arc costs were computed for the arcs where power flow was outside the range originally used for computing the unit costs. The hydro plants at Kistwar and Pakal Dal were not utilized fully in earlier computer runs and hence these were dropped from consideration in the sixth run. The resulting generation schedule and utilization of existing as well as proposed plants are shown in Table 6.

In all the solutions, the hydro plants were being utilized to the maximum possible extent except the proposed plants at Kistwar and Pakal Dal, as the cost of generation in hydro plants were the cheapest. Thus highest priority should be given to exploit the hydro resources and implement the proposed schemes. As the total installed hydro capacity may not be available during the peak demand period, specially following a dry year, proposed thermal plants at Faridabad, Panipat, Bhatinda, Kota and RAPP must be considered. Along with these plants, the existing plants at Kanpur and Harduaganj would provide enough capacity during a dry year, if hydro capacity is not fully available. Proposed plants at Panki and Harduaganj were found uneconomical with the cost data used, whereas the existing and proposed plants at Obra were utilized almost fully due to their better thermal efficiency and low cost of coal at Obra.

4 INTEGRATION OF THE NETWORK AND THE WASP MODELS

As discussed earlier, neglecting the transmission network from the power system formulation is a major limitation of the WASP model. The CONGEN and MERSIM modules in WASP model ensure that all system expansion configurations generated and simulated are feasible in terms of their meeting the projected system load as represented by the LOADSY module within limits of minimum and maximum plant capacity reserve margins and maximum allowable annual and period loss of load probabilities (LOLP). But due to the absence of any representation of the existing and proposed transmission network, it is not obvious that these configurations of generation expansion will satisfy the criterion that each load centre will be supplied with the required amount of power from the generating plants installed. In fact it is quite possible that due to certain bottlenecks in the transmission network, certain loads could not be met even if some of the generating plants have excess capacity. Again, there may be choices in terms of different locations for some of the thermal generating plants as well as choices regarding additional transmission links to be provided to cope with growth in system demand.

The DYNPRO module of WASP provides an optimal solution for the generation expansion plan by comparing the present value of discounted capital and operating costs during the plan horizon for each configuration. As transmission line expansions are not included in the model and alternative locations are not compared, DYNPRO solution could not be considered optimal in the true sense when the transmission networks are also taken into consideration. WASP model considers the outage of generating plants in computing the production cost and loss of load probability (LOLP), which is a major advantage of this programme, but as seen in practice, the reliability of a power system is highly dependent on the reliability of various transmission links and the nature of linkages between the generating plants and the load centres. Without considering the reliability of the transmission network, the LOLP computed in the WASP model gives only a partial solution.

In the planning methodology suggested for using the WASP programme, other auxiliary models are recommended for studying the loadflow, transient stability, and frequency stability characteristics, so that a stable power system is obtained. The maximum permissible generating plant unit size is also determined from stability considerations. These auxiliary programmes are essentially similar to a-c load flow and related programmes which can simulate a particular configuration of generating plants and transmission networks, but they cannot be used for optimization of the network based on economic considerations. The need for such studies to ensure the stability of the power system is very important and would be needed, whichever model is used for power system expansion planning. But there is need for analytical models which would determine the least cost expansion of the transmission network to meet growth in system load.

In the current section, a methodology for integrating the network planning model, discussed in the last section, within the general WASP framework will be discussed. This would provide a capability in the WASP programme to ensure that the generated configurations and consequently the optimal configurations obtained by the application of WASP model are feasible in terms of the transmission system being adequate and also optimal considering the transmission system expansion. The Network model could analyse whether each load centre could be supplied with the required amount of power from the generating plants through the existing transmission network and its planned expansions during the period of maximum demand and during any other critical period. In the WASP model framework this would be carried out by integrating the network planning model with the CONGEN module so that each expansion configuration would also include configuration of the existing and proposed expansion of the transmission network and the adequacy of the resulting transmission network would be examined by the network model. The Network model will also minimize the necessary expansion of the transmission network in some sense, making expansions only when it is necessary to provide for additional transmission links due to a bottleneck. Decisions on alternative locations of plants and alternative patterns of transmission line expansion are also examined.

As a second stage modification, it would be possible to integrate the network module also with the MERSIM and DYNPRO modules so that while the generating system simulation by MERSIM would provide the operating costs due to fuel, lubricants, etc., the operating costs due to power and energy losses in the transmission network would be determined from the solution of the Network model, and these two cost components for each configuration and each year will be added for storage in the MERSIM output file. The DYNPRO module would utilize the resulting operating cost information provided by the MERSIM module along with investment cost data on generating plants and transmission network expansions and provide an optimal solution which would minimize discounted costs of power generation and transmission in the system during the planning horizon.

The present structure of the probabilistic simulation programme in the WASP model, which schedules the generating plants to meet a given load, would limit the enlargement of the model from a single-node to a multi-node system. A multi-node simulation would require a strategy for optimally allocating and transmitting the generated power by the combined system of generating plants including thermal, hydro and pumped storage units at any time to the large number of load centres. This allocation could be solved by the network model for operational planning discussed in Section 3 for any particular load condition and state of the generating system describing plant outages. But to obtain values for operating hours for each generating plant during a year and values of energy not served and LOLP, the Network model will have to be solved for several load conditions, even if the annual load duration curve is represented by a discretized step function, and corresponding to each load condition for each state of the power generating system denoting the alternative possibilities of failure of generating plants. This task, even if it were manageable would require exhaustive computing effort to simulate all outage conditions of the generating system. This approach appears practical if probabilistic simulation is not used in the multi-node set up and the plant outages are taken care of approximately with a plant availability factor. In the present WASP model, probabilistic simulation is carried out by generating equivalent load duration curves as seen by each plant in the loading order . As this is done for only one load centre, this problem of allocation does not arise. This strategy for probabilistic simulation cannot be easily extended to a multi-node power generation and transmission network system.

For a realistic probabilistic simulation of the power generating and transmission system a more generalized approach will be needed which will also include reliability analysis of the transmission network. At present work is under way to develop a special Network model for reliability analysis of a multi-node power generation and transmission system which could form the basis for such a generalized approach.

The additional data input needed for integrating the Network planning model as a separate module (NETRAN for Network Transmission) into the WASP package is related to the locations of the generating plants, the topology of the transmission network and the cost data for investment and operation of the transmission system. In the FIXYS and VARSYS modules, information regarding the location of each existing and proposed power plants should be provided in terms of a code number. Space is already available in the WASP data input setup for including information on the location of generating plants. This location space which was not used before in the earlier versions of WASP II model is now being used for certain other data inputs (percentage of fast spinning reserve capacity) in a new version of WASP II with a modified unit loading subroutine in MERSIM. The two-digit space for location would be enough for providing distinct code numbers for 99 nodes if a numeric code is used. But using an alpha-numeric code, e.g. A5, C7, etc., 234 locations could be covered by the two-digit location space. This maybe sufficient for representing reasonably large power systems.

Similarly, information regarding existing and proposed transmission lines should be provided in the FIXYS and VARSYS modules. A transmission line is represented by a directed arc in the Network model and it should be denoted by the location of its initial and terminal nodes. To represent the possibility of power flowing in either direction in a transmission line connecting the nodes x and y, arcs (x,y) and (y,x) must both be included. The other data needed for each transmission line would be the KVA rating, number of circuits, conductor size (cross sectional area), length of the transmission line (in kilometers), capital cost of installation per unit length and a factor to be used for computing average power and energy losses in the transmission line. If a Network model satisfying both the First and Second Laws of Kirchoff is used then additional information regarding the resistance and reactance of the transmission line per unit length should be provided. From these basic data on transmission lines, the upper limits on power flow in megawatts (MW) in the transmission line and the unit investment costs and operating costs due to maintenance and power losses could be computed. Similarly, the node-arc incidence matrix, admittance matrix and independent mesh matrix could also be determined from the transmission network data for use in a network model (d-c load flow) satisfying the First and Second Kirchoff's laws.

Additional data regarding the load at each load centre should be provided in the LOADSY module. Initially it is assumed that the load duration curves for all the load centres are identical and that information regarding th peak demand at each lo i centre during th annual or period peak demand for the total system is available. These data should be provided against the two-digit location information for each load centre. If a generating plant and a load centre are physically located next to each other, then also separate nodes must be used to denote them, with an arc of negligible length joining them. Due to the seasonal variability in the availability of hydro capacity and energy, if it is desirable for checking the feasibility of the transmission network during any other time besides during the annual critical period when maximum system peak demand occurs, the load data for each load centre for such times will have to be provided. Unless there is much diversity in the load duration curves and in the chronological load patterns of different load centres, this method would be satisfactory. However, if there are wide differences between various load centres in the distribution of loads during the year, it may be better to work with chronological load curves to determine critical periods during which transmission system feasibility should be examined. As WASP is dependent on using the period load duration curve, it will not be possible to use chronological load curves within the WASP framework, but such curves could be used exogenously to determine critical periods.

In the CONGEN module, additional input data should be provided to guide the NETRAN module in planning the expansion of the transmission network. For each generation system expansion configuration produced by CONGEN for any year the plant location code should be provided along with the type and capacity of the plants. If alternative locations for the same plants are to be considered, these must be denoted as separate plants and separate configurations must be generated, as these configurations might require different types of expansions for the transmission system with varying investment requirements The total number of configurations generated by CONGEN module will thus increase to some extent depending on the number of generating plants for which alternative locations are considered. The Network model application discussed in Section 3 illustrates this issue as four alternative locations for a nuclear plant were analysed for the Northern Region power system in India.

As suggested above the Network Planning model for power system planning discussed in detail in Section 3 should be introduced as a separate module 'NETRAN' in WASP after it is suitably modified to serve as a transmission network planning model, and it should be run following the CONGEN module but before the MERSIM and DYNPRO modules. The NETRAN module will read the data files generated by FIXSYS, VARSYS and CONGEN modules and generate its own output file, denoted by TRANSALT, for subsequent use by MERSIM and DYNPRO modules for probabilistic simulation and optimization of the power system.

The output data files created by FIXSYS will now contain additional information regarding the location of all existing generating plants and the node-arc representation of the existing transmission network along with characteristics and operating costs of all existing transmission lines. Similarly the output data files created by VARSYS will now contain additional information regarding alternative (if any) locations for proposed plants as well as characteristics, investment and operating costs data for proposed alternative transmission line additions and the first year they could be commissioned. The CONGEN output file will now contain additional generating system configurations to represent alternative locations, if any, for proposed generating plants and in general location code for all proposed plants.

The basic function of the NETRAN module would be to analyse, for each configuration of generating system expansion created by CONGEN, the power flow in the associated transmission network from the generating plants to the load centres during peak period, and at any other critical period. If during a particular year, the existing transmission network is viable to meet the peak load (augmented by a minimum transmission reserve margin) at all load centres, then the capacity of the transmission network would be increased suitably by providing additional transmission lines from those proposed in VARSYS or by increasing the capacity of some of the existing lines, if feasible. NETRAN ensures that transmission system expansions are carried out in an optimal manner, in the sense that investments made during each such transmission system expansion is carried out at the lowest cost. The size of each transmission system expansion and the total expansion during the planning horizon in terms of megawatt carrying capacity will depend on the annual rate of demand growth at load centres, the base year demand, and the percentage minimum reserve margin taken for transmission system. NETRAN would also compute the operating costs for the transmission system for each period in each year of the planning horizon following optimal transmission expansion and this data will be added later with the operating costs of the power generating system as computed in MERSIM module. The total system operating costs along with investment costs for generating plants and transmission lines will be then used in DYNPRO for selecting the best or least cost generating and transmission system configurations.

In the methodology proposed in this section NETRAN module is proposing only one transmission system configuration for each generating system configuration suggested by CONGEN module and presumably the least cost one. The sequential augmentation of the transmission system also ensures that the configuration suggested for a later year could be obtained from the configuration of an earlier year a property also followed by the generation system configurations produced by CONGEN. Only minimum reserve margin is used for planning the transmission system expansion so that the transmission system could sustain certain amount of overload due to excess demand from any of the load centres. It is possible to generate more than one transmission system expansion configurations corresponding to each configuration of generating system expansion produced by CONGEN to consider the effect of economies-of-scale in transmission system expansion but this would increase the total number of power system configurations to a great extent with consequent increase in computational effort. Simulation of alternative transmission expansion configurations is also not considered necessary following the running of NETRAN module as contrary to the way CONGEN generates the expansion alternatives for the generating system, NETRAN simulteneously analyses the expansion alternatives for the transmission systems and retains only the least cost one. It might be better to use the Network model in conjunction with the dynamic programming approach as suggested in Section 2 to consider the effect of economies-of-scale in transmission system planning, but then this should be done within the framework of the DYNPRO module in WASP package which uses a dynamic programming optimization subroutine.

The NETRAN module proposed for inclusion in the WASP package at present has no capability for analysing and evluating the reliability of the transmission network and carrying out transmission planning to improve the reliability by providing redundant links as required. Work is under way to design a program for this purpose which could be included in the NETRAN module for evaluating the reliability of a power system configuration due to outage of generating plants as well as transmission lines and supplement the LOLP information provided by the MERSIM module.

In case CONGEN produces too many generating system expansion configurations, the NETRAN module could be used to screen through them while it carries out transmission system analysis and planning. Generating plant cost data is used in NETRAN so that economic loading order is followed in generating the power flow pattern through the transmission network. Thus alternative configurations produced by CONGEN could be compared by NETRAN and ranked in order of decreased cost and obviously poor candidates could be dropped from further consideration. If such configurations are on the boundary and flagged later by the solution of the DYNRPO module they could be reintroduced during the following MERSIM-DYNPRO run and so nothing is lost by dropping these configurations, whereas the computational effort in MERSIM and DYNPRO for simulating them will be saved if these are not on the boundary due to this early screening by NETRAN model.

Similar to the CONGEN and MERSIM modules, the NETRAN module also proceeds sequentially, starting with the first year of the planning horizon, the analysis of the transmission network and planning its expansion. Thus the Network model in NETRAN works similar to the operational planning model described in Section 3, and simulates the operation of the power system during the peak period every year. For each configuration of generating system expansion during the first year of the planning horizon, as provided by CONGEN output, the analysis of the transmission system is started by the NETRAN module with the existing transmission network. This configuration is maintained for runs during the first and subsequent years until during one of the years for a particular configuration of the generating plants and their location, it is shown that the existing transmission network is no longer sufficient to supply peak power demand at all the load centres. The VARSYS output file is then checked for possible transmission line expansion candidates. If proposed lines are not suitable then a message should be printed out. The transmission system is augmented with one or more arcs connecting nodes across the minimal cut set [9] obtained as a result of the solution of the Network Model in NETRAN. These additions are additional links usually of the same KVA rating as the existing links but in case the amount of power flow in the network justifies going to a higher KVA rating, then the next higher KVA rating is included if such transmission line additions have been proposed in VARSYS. It is possible to augment the transmission capacity of a network by providing additional links to connect nodes already joined by transmission lines across the minimal cutset or by linking unconnected nodes across the minimal cutset and thereby effectively increasing the capacity of the minimal cutset. In this process though the flow bottleneck across the minimal cutset is removed, bottlenecks elsewhere in the network may remain represented by other cutsets of the same or marginally higher value. The best strategy is to apply the network algorithm in an iterative manner after each addition to the transmission system to determine the least cost flow pattern in the network so that ultimately the network becomes feasible for supplying the growth of demand at all load centres for the year.

The NETRAN programme solution would then be continued for generating least cost transmission system expansion configurations in subsequent years. Work is in progress to develop an interactive Network model with visual display of the power system network, so that the model user would be guided in his choice of expansion candidates by the visual display and the solution of the model. Instead of providing minimal transmission link additions whenever necessary, if the programme is used in an interactive mode, the user could use his judgement in terms of adding transmission links of higher KVA rating or providing different alternatives by connecting two unconnected nodes so that the augmented transmission capacity is sufficient to accommodate the load growth plus reserve requirement in the system for several years in the future. But with a large power system network with several hundreds of nodes and arcs this would not be easy even if a visual display is available of the system network and the use of a programme which makes minimal cost additions from the suggested candidates is recommended. Similar to the augmentation of generating plants by using minimum and maximum reserve margins in CONGEN, transmission line expansions could also be made to satisfy minimum reserve margins based on equal rates of load growth at all load centres. As an alternative approach to the sequential planning of the transmission system, the total planning horizon (of say 20 years) could be divided into several equal periods of medium duration (of say five years) and determine least cost transmission network expansion configurations to satisfy demands during these periods. Thus, to determine the optimal expansion of the transmission line for meeting growth in demand at the load centres two alternative strategies are available. The sequential approach discussed first would use the network model to determine the minimum cost additional links required to make the transmission network feasible. An alternative approach would be to use the network model for the solution of minimum cost power transmission problem at designated periods during the planning horizon to obtain optimal network design. These two approaches are very similar to apply except that the second approach might result in capacity expansion in large steps as compared to the former and where it should be used would depend on whether there are large economies-of-scale in transmission line expansion which the sequential approach cannot take into account. If the NETRAN module is being solved in an interactive mode with visual display, and user interruption during periods when the transmission networks get saturated, then the sequential approach would be more suitable. In the second approach transmission system expansion configurations are provided as input data in VARSYS and NETRAN determines the minimum cost transmission line expansion at designated periods during the planning horizon from these configuration of all possible alternative expansions. Further experimentation with the integration of the network model in NETRAN in the WASP package would be necessary before either of these strategies is recommended as the desirable one for general use.

Based on the data contained in the output files created by FIXSYS, VARSYS, LOADSY and CONGEN modules, a conceptual system network is created by NETRAN corresponding to each generating system expansion configuration during the peak period of each year. During the first year of the planning horizon, all the fixed system generating plants, corrected for plant additions and retirements, as well as expansion configurations suggested by CONGEN are treated as existing plants in the terminology of Section 3, and only the operating costs, due to fuel, lubricants and maintenance is charged as unit cost per megawatt in the generation arcs in which the maximal flow would be limited by the maximum available plant capacity.

As discussed earlier, the fixed system transmission lines are treated as existing transmission lines and only costs due to maintenance and power loss are charged against these arcs. If the generation system expansion suggested by CONGEN has introduced any new generating nodes or if LOADSY has introduced any new load centres, or demand nodes then the network must be augmented by new arcs to connect these new nodes to the network from transmission lines proposed in VARSYS before the network model is run. All new transmission arcs added are treated as proposed arcs and their unit costs reflect the contribution of capital costs as well as operating costs.

If the solution of the network model (NETFLOW) for the first year produces a feasible minimum cost power flow pattern through the existing transmission network, possibly augmented by new lines to connect new generating plants and load centres, the same transmission system is transferred to the next year as the existing system. The minimum total cost of operating the transmission system during the peak hour is multiplied by the annual hours of operation and load factor to obtain annual costs of operation.

If, however, the network model solution is infeasible indicating that some transmission bottleneck is present, the transmission system expansion subroutine (TRANSLINK) is called, which adds new transmission links based on the information available from the model solution regarding the minimal cutset and the unserved demand, i.e., the amount of power in megawatt that could not be supplied through the current transmission network. From the candidates suggested in VARSYS, the transmission link(s) with the lowest cost is chosen by TRANSLINK which would increase the capacity of the minimal cutset by an amount at least equal to the unserved demand in megawatts. As the capital costs of transmission arcs are directly proportional to their length in kilometres, when choosing from transmission lines of the same KVA rating, the line with the shortest length spanning the minimal cutset could be chosen. Otherwise a simple comparison between transmission lines of different KVA rating will decide the best candidate(s) for system expansion.

The network model (NETFLOW) and the transmission system expansion subroutine (TRANSLINK) are then called in an iterative manner until NETFLOW produces a feasible flow pattern for the current year through the transmission network augmented by TRANSLINK. The annual cost of operating the transmission system including the annualised cost of additions to the transmission system is then computed and the resulting transmission network is transferred for analysing the load in the following year with the same values of unit arc costs and capacities. During all subsequent years, for the new transmission arcs, the capital cost component of the unit arc cost is maintained at the same value in the NETFLOW solutions though these arcs are treated as existing arcs in the transmission network. At the completion of the network model (NETFLOW) solution in the NETRAN module for the first year, corresponding to each generating expansion configuration analysed, an optimal transmission network design is available, all of which may not be distinct from each other. For the generating expansion configurations for the next year which can be reached from a particular configuration in the first year, the NETFLOW solution is started with the corresponding transmission network design and if required TRANSLINK is called to add additional transmission links to the network. Following this sequential application of the Network model in the NETRAN module, a consistent set of co-ordinated expansion configurations for the generating and transmission system is generated and these configurations along with annual operating costs for each transmission expansion configuration is stored in the TRANSALT file, the output file for the NETRAN model. As the annual cost of operating the generating plants and their hours of operations is determined more accurately following probabilistic simulation method in the MERSIM module, these computations are not done in the NETRAN module. A flow sheet of the NETRAN Module is shown in fig. 3.

It is proposed to include a transmission network reliability programme (NETREL) in the NETRAN module in the future, which given the reliability of the generating plants and transmission lines would compute the reliability of the power system and supplement the LOLP computation that is now carried out in the MERSIM module. The MERSIM module will also use the TRANSALT file to obtain operating cost data for the transmission system which added to the generating cost data will provide total cost of operation. The DYNPRO module will also use TRANSALT file along with the other files to obtain transmission system expansion schedule and corresponding capital investments made, to be used in determining the least cost power system expansion schedules.

The suggested methodology for the integration of the Network model in the WASP package as the NETRAN module could be developed further to improve the capability of the WASP model in the area of transmission system expansion planning. It is seen that in addition to designing optimal transmission system expansion plans the network model if incorporated as a separate module in WASP could assist in making locational decisions for generating plants and also in screening the large number of expansion configurations produced by CONGEN by using the cost information generated by the solution of the Network model. With the incorporation of the additional NETRAN module in the WASP package, a multi-node representation of the power system including the generating plants and the transmission network will be available and WASP model solutions including transmission system expansion plans would become more realistic and useful. Often the transmission system becomes the bottleneck in meeting peak power demands at the load centres even when sufficient generating capacity is available. NETRAN module with its fast computer routines will assist WASP model in removing the bottlenecks. Further experimentation may be required to determine the best strategy for the introduction of the NETRAN module in the WASP package and the working of the module in coordination with the other WASP modules, but based on the experience gained in applying both the WASP model and the Network model in power system planning studies, the strategy presented above appears best as an initial level modification for improving the capability of the WASP model for power system planning in the developing countries.

5. OTHER IMPROVEMENTS AND MODIFICATIONS OF THE WASP PACKAGE

Various other improvements and modifications of the WASP model to improve its capability and efficiency have been suggested earlier by the large number of users of the WASP package both informally and also in WASP Users' conferences held at Tennessee Valley Authority, Chattanooga, USA. The major improvements and modifications suggested include (i) a better representation of hydroelectric power plants, (ii) improvement in LOLP and maintenance scheduling computation, (iii) improvement of the present probabilistic simulation programme based on Fourier series representation of the period load duration curve, (iv) conversion of WASP into an interactive programme to be used with time-sharing facilities, (v) multi-region representation in WASP package including power transfer within regions and allocation of proposed generating plants among the regions, (vi) representation of the transmission system and, (vii) improvement in the communication and information flow between the WASP modules to improve its computational speed and efficiency.

During the course of this paper some of these improvement proposals have been discussed and the proposed NETRAN module would provide at least two of these improvements mentioned above without substantially increasing the computational requirements of the WASP package. In this concluding section, a related improvement and modification of the WASP package will be discussed. Further experimentation with the WASP package is required to develop these ideas into definite computational schemes, but if they could be implemented, it is expected that the computational requirements for the solution of the WASP model could be substantially reduced.

In the current WASP framework, CONGEN, MERSIM and DYNPRO modules are solved in a sequential manner. CONGEN generates all feasible system expansion configurations which satisfy the minimum and maximum reserve margin and LOLP criteria provided. LOLP computation within CONGEN is simpler and does not include maintenance requirements of the generating units. MERSIM sequentially simulates each configuration generated by CONGEN and determines system operating costs and LOLP using the probabilistic simulation programme (based on a more accurate computation considering both plant outages and maintenance requirements). DYNPRO uses the cost and reliability data provided by MERSIM along with other data regarding foreign and local distribution of cost and discount rate to generate five or ten best optimal system configurations. This sequential methods of solution has certain advantages as it is modular in nature. It reduces the computer memory requirements and the need for rapid access between these three modules. However, it is not a very efficient method to compute the optimal configuration as a very large number of configurations may be generated by CONGEN and simulated by MERSIM which might all be ultimately eliminated by the DYNPRO module from cost considerations. While generating additional configurations, the CONGEN module has no information regarding the cost of the configurations already generated. It is conceived that if it is possible for these three modules to communicate with each other and work simultaneously, the computational effort could be reduced considerably by eliminating a large number of configurations which has to be simulated now at large computer cost.

Essentially, the modification suggested here is that CONGEN should use the cost information provided by MERSIM on the configurations it has already generated, and use this information to decide on the additional configurations that it should generate next. Thus computational schemes similar to the 'branch and bound' method of integer programming [7] might be devised by combining the CONGEN, NETRAN, MERSIM, and DYNPRO modules to obtain an optimum expansion configuration. The importance of this aspect of the computational process in WASP becomes very important when transmission system is included due to two reasons. Firstly, in deciding the transmission system augmentation, NETRAN module will use some cost information as described in Section 4, mainly the investment costs in Transmission network expansion, to obtain a minimum cost transmission system expansion, and this cost information could be used to screen the CONGEN output. Secondly, during the solution of MERSIM module, the cost of generating system operation is also available along with the cost of transmission losses provided by NETRAN module. As discussed in Section 3, the Network planning model could simultaneously analyse the expansion of both the generation and transmission systems and it also uses a very fast computer routine for determining the optimum solution. It is thus conceivable that the Network model in NETRAN could be used to atleast screen through a large number of possible configuration expansions before detailed simulation of the suggested configurations are taken up by MERSIM.

Even within the present computational framework of WASP, which consists in the sequential solution of CONGEN, MERSIM and DYNPRO modules, it would be possible to design a more powerful CONGEN module by the integration of the network planning model within CONGEN or provide an independent NETRAN module, so that a large number of non-optimal configurations are screened out and a few of the probable candidates listed for detailed simulation by MERSIM and subsequent optimization by DYNPRO. In case a modified computational framework is adopted integrating the CONGEN, NETRAN, MERSIM and DYNPRO modules, then it is possible to use the network planning model as a screening device in the suggested 'branch and bound' algorithm to direct the configuration generation operation in CONGEN by following the proper branching procedures. Thus the network planning model would not only provide capability to acoommodate transmission system representation in the WASP model, it would also serve as a fast computer routine to screen out a large number of configurations which are not promising and only provide a few promising ones for detailed simulation by MERSIM and subsequent optimization by DYNPRO.

Integration of the four modules also introduces other possibilities mentioned earlier such as development of a combined approach for transmission system expansion planning by using simulteneously the network model in NETRAN and the dynamic programming algorithm used in DYNPRO. The implementation of these ideas will, however, require that the computational framework of the WASP package and the information flow scheme is redesigned to accommodate simultaenous solution of the four modules with possibility of communication and rapid information exchange between these modules. The efficiency gained through reduced computational effort must be weighed against the increased memory requirements and complexity of the resulting computer package. It is expected that further research will be undertaken in this area and these ideas will be explored for devising improvements in the computational framework of the WASP package to improve its speed, efficiency and problem solving capability.

Annex 1

SUMMARY DESCRIPTION OF WASP MODULES

LOADSY module receives input data regarding peak system demand and the shape of the load duration curve (expressed as a fifth order polynomial function) for each period (maximum periods in a year is 12) during each year of the planning horizon and prepares a summary of system power and energy demand for each period. LOADSY represents the load duration curve as a Fourier series which is subsequently used by other WASP modules.

FIXSYS modules receives input data regarding the existing generating plants of different types--hydro (normal, emergency and pumped storage), thermal (coal, oil or lignite-fired) and nuclear--and capital, fuel and O & M costs for these plants broken into domestic and foreign components and prepares fixed system data files for use by subsequent modules.

VARSYS module receives input data regarding the proposed generating plants of different types--hydro (normal, emergency and pumped storage), thermal (coal, oil or lignite-fired) and nuclear--and capital, fuel and O & M costs for these plants broken into domestic and foreign components and prepares data files for use by subsequent modules.

CONGEN module of WASP creates a file listing the year-to-year alternative system configurations using various combination of plants described in VARSYS along with the fixed system described by FIXYS, each of which satisfies some criterion regarding minimum and maximum system reserve margin and period and annual loss of load Probability (LOLP) specified by the user.

MERSIM module of WASP considers all acceptable future system configurations generated by CONGEN and simulates system operation using each configuration for each period in a year for each hydrological condition (specified by the user up to a maximum of 5 conditions with stated probabilities of occurance) using probabilistic simulation techniques which considers plant forced outages and maintenance needs to compute fuel and O & M costs for each plant based on expected hours of operations, LOLP and energy not served for the system.

DYNPRO module of WASP carries out the economic evaluation of alternative expansion schedules generated by CONGEN and simulated by MERSIM using well known dynamic programming principles and chooses the lowest-cost expansion schedule over the planning horizon, based on the comparison of present worth value of all future costs of each configuration possibly modified by a shadow exchange rate for foreign costs and annual escalation factors provided by the user. To allow for terminal conditions, salvage value for plants in the terminal year are taken according to liner or sinking-fund depreciation rules. Several of the best (up to a maximum of 10) economic solutions could be printed out. The WASP package also has an additional module REPROBATE for generating a summary executive report following a WASP run.

TABLE-1

Load Centres in Northern Region & Their Peak Demands in 1978-79

S.No.	Load Centre	Peak Demand (MW)	S.No.	Load Centre	Peak Demand (MW)
1	Pipri	283	23	Yamuna	37
2	Mughalsarai	293	24	Jullundar	327
3	Gorakhpur	261	25	Ludhiana	411
4	Sultanpur	183	26	Muktasar	97
5	Allahabad	149	27	Sangrur	118
6	Kanpur	423	28	Bhatinda	148
7	Lucknow	218	29	Bhakra	381
8	Mainpuri	149	30	Rupar	56
9	Bareilly	141	31	Amritsar	276
10	Harduaganj	189	32	Udaipur	132
11	Moradabad	162	33	Kota	225
12	Muradnagar	326	34	RAPP	89
13	Narora	63	35	Jaipur	192
14	Shamli	98	36	Alwar	47
15	Saharanpur	71	37	Sawaimadhopur	61
16	Delhi	660	38	Jodhpur	29
17	Ballabhgarh	252	39	Khetri	46
18	Nehtaur	56	40	Ratnagarh	26
19	Panipat	135	41	Bihaner	23
20	Hissar	214	42	Beawar	40
21	Rishikesh	101	43	Bhilwara	40
22	Roorkee	81			

TABLE 2

Existing and Proposed Generating Stations Upto 1978-79 for Northern Region

S.No.	Generating Station	Type	Existing / Proposed	Maximum Capacity (MW)
1	Obra	Hydel	Existing	100
2	Rihand	Hydel	Existing	300
3	Obra	Thermal	Existing	1500
4	Kanpur	Thermal	Existing	155
5	Panki	Thermal	Proposed	220
6	Harduaganj	Thermal	Existing	190
7	Harduaganj (Extn.)	Thermal	Proposed	550
8	Tehri	Hydel	Proposed	300
9	Ramganga	Hydel	Existing	240
10	Delhi	Thermal	Existing	360
11	Faridabad	Thermal	Proposed	400
12	Panipat	Thermal	Proposed	220
13	Yamuna (Stages I to IV)	Hydel	Existing	800
14	Maneri Bhali	Hydel	Proposed	405
15	Vishnu Prag	Hydel	Proposed	120
16	Bhakra L.B.	Hydel	Existing	450
17	Bhakra R.B.	Hydel	Existing	600
18	Dehar	Hydel	Existing	340
19	Dehar (Extn.)	Hydel	Existing	660
20	Siul	Hydel	Existing	200
21	Thein	Hydel	Proposed	420
22	Seawa	Hydel	Proposed	100
23	Salal	Hydel	Existing	270
24	Kistwar	Hydel	Proposed	200
25	Pakal dal	Hydel	Proposed	200
26	Bhatinda	Thermal	Existing	220
27	Bhatinda (Extn.)	Thermal	Proposed	220
28	RP Sagar	Thermal	Existing	172
29	Kota	Thermal	Proposed	440
30	RAPP	Thermal	Proposed	400
31	Rupar*	Nuclear	Proposed	470
32	Narora*	Nuclear	Proposed	470
33	Matatila*	Nuclear	Proposed	470
34	RAPP*	Nuclear	Proposed	470

*These are 4 alternative locations for the proposed Nuclear plant.

TABLE - 3

Existing and Proposed Transmission Lines Upto 1978-1979

S.No.	Transmission Lines	Existing(E) Or Proposed(P)	Rating KV and No.of Circuits	Route Length (KM)
1	Obra - Pipri	E	132 DC	34
2	Obra - Pipri	P	220 DC	34
3	Pipri - Mughalsarai	E	132 DC	129
4	Mughalsarai - Gorakhpur	E	132 DC	204
5	Mughalsarai - Gorakhpur	P	220 DC	204
6	Obra - Mughalsarai	E	220 DC	97
7	Obra - Mughalsarai	P	400 SC	97
8	Obra - Sultanpur	E	400 SC	253
9	Sultanpur - Gorakhpur	E	220 SC	148
10	Obra - Allahabad	E	220 DC	177
11	Obra - Allahabad	P	400 SC	177
12	Allahabad - Sultapur	E	132 SC	111
13	Allahabad - Kanpur	E	220 DC	208
14	Kanpur(Gen.) - Kanpur	E	220 DC	0
15	Kanpur - Lucknow	E	220 DC	90
16	Kanpur - Lucknow	P	132 SC	90
17	Kanpur - Lucknow	P	220 SC	90
18	Sultanpur - Lucknow	P	220 SC	130
19	Kanpur - Mainpuri	E	220 DC	150
20	Matatila - Kanpur	E	132 SC	257
21	Matatila - Kanpur	P	220 SC	257
22	Matatila - Allahabad	P	220 SC	230
23	Matatila - RAPP	P	220 SC	230
24	Lucknow - Bareilly	E	132 DC	259
25	Tehri - Bareilly	P	220 DC	200
26	Mainpuri - Harduaganj	E	220 DC	128
27	Harduaganj(Gen) - Harduaganj	P	220 DC	0
28	Harduaganj - Muradnagar	E	220 DC	105
29	Harduaganj - Muradnagar	P	400 SC	105
30	Narora - Harduaganj	P	220 SC	65
31	Narora - Muradabad	P	220 SC	65
32	Narora - Mainpuri	P	220 SC	135
33	Moradabad - Bareilly	E	132 DC	85
34	Muradnagar - Muradabad	E	132 SC	128

SC - Single Circuit   DC - Double Circuit

contd

TABLE 3 (Contd..)

S.No.	Transmission Lines	Existing(E) Or Proposed(P)	Rating KV and No.of Circuits	Route Length (KM)
35	Rishikesh(Gen)-Rishikesh	P	220 DC	0
36	Rishikesh - Muradnagar	P	400 SC	175
37	Rishikesh -Moradabad	P	400 SC	160
38	Moradabad - Nehtaur	E	132 DC	64
39	Nehtaur - Roorkhee	E	132 DC	83
40	Rishikesh - Muradnagar	E	220 SC	175
41	Rishikesh - Roorkhee	E	132 SC	49
42	Saharanpur - Roorkhee	E	132 SC	31
43	Muradnagar - Shamli	E	220 SC	48
44	Shamli - Sharanpur	E	220 SC	50
45	Yamuna - Saharanpur	E	220 SC	85
46	Yamuna - Rishikesh	E	220 SC	70
47	Shamli - Panipat	E	220 SC	160
48	Muradnagar - Delhi	E	220 DC	43
49	Hissar - Panipat	E	132 SC	115
50	Hissar - Delhi	E	220 DC	198
51	Hissar - Ballabhgarh	P	220 DC	225
52	Bhakra - Panipat	E	400 SC	280
53	Bhakra - Panipat	P	400 SC	280
54	Bhakra - Rupar	E	132 DC	70
55	Rupar - Ludhiana	E	132 DC	100
56	Rupar - Sangrur	P	220 DC	135
57	Bhakra - Ludhiana	E	220 DC	86
58	Bhakra - Ludhiana	E	220 DC	86
59	Ludhiana - Jullundar	E	220 DC	58
60	Ludhiana - Jullundar	E	132 DC	58
61	Ludhiana - Jullundar	E	220 SC	58
62	Dasuya- Jullundar	E	220 DC	56
63	Dasuya - Jullundar	P	220 SC	56
64	Jullundar - Amritsar	E	220 SC	80
65	Jullundar - Amritsar	E	132 SC	80
66	Ludhiana - Bhatinda	E	220 SC	128
67	Bhatinda - Sangrur	E	220 SC	112
68	Ludhiana - Muktasar	E	132 DC	144
69	Ludhiana - Sangrur	E	220 DC	240
70	Sangrur - Hissar	E	220 DC	144
71	Hissar - Khetri	E	220 SC	115
72	Jaipur - Khetri	E	220 SC	144
73	Hissar - Ratangarh	E	132 SC	208
74	Panipat - Jaipur	E	220 SC	280
75	Panipat - Jaipur	P	400 SC	280

contd...

TABLE 3 (Contd..)

S.No.	Transmission Lines	Existing(E) Or Proposed(P)	Rating KV and No.of Circuits	Route Length (KM)
76	Alwar - Delhi	E	220 SC	125
77	Jaipur - Alwar	E	220 SC	100
78	Jaipur - Alwar	E	132 SC	100
79	Alwar - Harduaganj	E	132 SC	210
80	Mainpuri - Swaimadhopur	E	132 SC	325
81	Swaimadhopur - Jaipur	E	132 SC	128
82	Swaimadhopur - Jaipur	P	220 SC	128
83	Jaipur - Beawar	E	132 SC	200
84	Jaipur - Beawar	P	220 SC	200
85	Beawar - Jodhpur	E	132 SC	152
86	Bhilwara - Jodhpur	E	132 SC	245
87	Bhilwara - Beawar	E	132 SC	93
88	RAPP - Bhilwara	E	132 SC	120
89	Kota - Bhilwara	E	132 SC	120
90	Kota - RAPP	E	220 DC	43
91	Kota - Jaipur	E	220 DC	187
92	RAPP - Jaipur	P	400 SC	230
93	Kota - Beawar	P	220 SC	187
94	Kota - Swaimadhopur	E	132 DC	112
95	Kota - Swaimadhopur	P	220 SC	112
96	Moradabad - Nehtaur	P	220 DC	64
97	Yamuna - Saharanpur	P	220 SC	85
98.	Saharanpur - Roorkhee	P	132 SC	31
99	Yamuna - Muradnagar	P	400 SC	260
100	Hissar - Panipat	P	220 SC	115

TABLE 4

Characteristics for Various Transmission Lines

Sr. No.	Transmission Line KV rating	Conductor Size, mm	K Factor Watts.	Capital cost Rs.'000/Km.	Range of power Transmission KW
1	400 KV SC	325	0.505	275	150 - 600
2	220 KV DC	325	0.835	230	100 - 300
3	220 KV SC	325	1.669	137	50 - 150
4	132 KV DC	185	4.065	127	50 - 100
5	132 KV SC	185	8.13	78	0 - 50

SC - Single Circuit; DC - Double Circuit

TABLE 5

Cost of Transmission Used for the Study

(Values are taken from the graphs plotted for individual cost function)

	Cost (Rs./Km/Year/MW)	Capacity Range (MW)
EXISTING LINES		
132 KV SC	140	40 - 50
132 KV DC	140	80 - 100
220 KV SC	85	120 - 150
220 KV DC	85	240 - 300
400 KV SC	110	500 - 600
PROPOSED LINES		
132 KV SC	370	40 - 50
132 KV DC	335	80 - 100
220 KV SC	200	120 - 150
220 KV DC	185	200 - 300
400 KV SC	150	400 - 600

TABLE 6

Pattern of Plant Utilization Under Different Assumptions : Summary of Computer Runs

Type	Generating Stations	Max. Capacity MW	Power generated in MW in optimal solution					
			1st run	2nd run	3rd run	4th run	5th run	6th run
Existing Hydro Plants	Rihand } Obra }	(400)	400	400	300	200	200	200
	Ramganga	(240)	240	240	200	120	120	120
	Yamuna	(800)	650	650	400	400	400	400
	(Bhakra L.B., R.B.,Dehar I &II)	(2050)	2050	2050	1600	1025	1025	1025
	Siul	(200)	200	200	160	100	100	100
	Salal	(270)	270	270	220	130	130	130
Existing Thermal Plants	Obra	(1500)	1219	1219	1319	1419	1419	1419
	Kanpur	(155)	-	-	-	155	155	143
	Harduaganj	(190)	-	-	162	190	190	190
	Delhi	(360)	360	360	360	360	360	360
	Bhatinda	(220)	72	116	220	220	220	220
	RP Sagar	(172)	172	172	172	172	172	172
	ehri	(300)	300	300	250	150	150	150
Proposed Thermal Plants	Panki	(220)	-	-	-	-	-	-
	Harduaganj	(550)	-	-	-	-	-	-
	Faridabad	(400)	-	-	-	-	400	400
	Panipat	(220)	-	-	-	220	220	220
	Bhatinda	(220)	-	-	-	103	90	128
	Kota & RAPP	(840)	-	-	275	840	840	840
Proposed Hydro Plants	Tehri	(300)	300	300	250	150	150	150
	Rishikesh	(525)	525	525	420	260	260	260
	(Maneri bhali & Vishnu Prag)	(520)	520	520	420	260	260	260
	Dasuya (Thein & Seawa)	(520)	520	520	420	260	260	260
	Amritsar (Kistwar & Pakal Dal)	(400)	113	-	157	26	26	-

contd..

TABLE 6 (Contd..)

Type	Generating Stations	Max. Capacity MW	Power generated in MW 1st run	2nd run	3rd run	4th run	5th run	6th run
Proposed Locations for a Nuclear Plant	Rupar	(470)	-	-	-	-	-	-
	Narora	(470)	-	20	212	-	363	363
	Matatila	(470)	123	178	273	350	-	-
	RAPP	(470)	6	-	-	-	-	-
Total Cost per annum (in Rs. million)			1471	1488	1858	2576	2553	2557

Notes: In 3rd run Hydro capacity was reduced to 75% of maximum and Rupar, RAPP locations were neglected for proposed nuclear plant.

In 4th run Hydro capacity was reduced to 50% of maximum and nuclear plant location at Matatila was considered.

In 5th run Hydro capacity was reduced to 50% of maximum and nuclear plant location at Narora was considered.

In 6th run proposed hydro plants at Kistwar and Pakal Dal were neglected and costs on some transmission lines were changed for increasing accuracy.

FIGURE 1. NETWORK MODEL PRESENTATION OF A HYPOTHETICAL POWER SYSTEM.

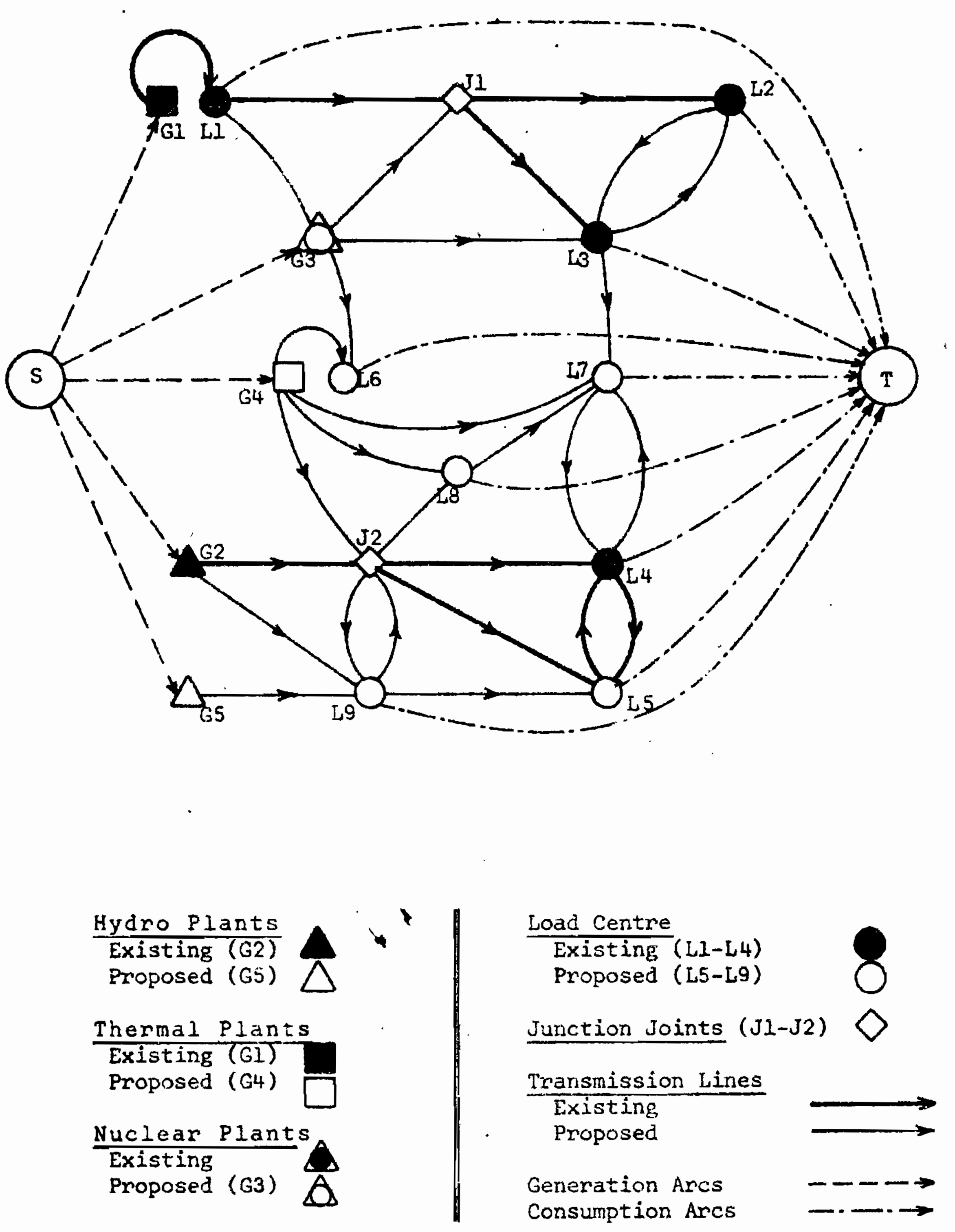


FIGURE 2

NORTHERN REGION POWER SYSTEM

NETWORK MODEL OPTIMAL SOLUTION NO 5

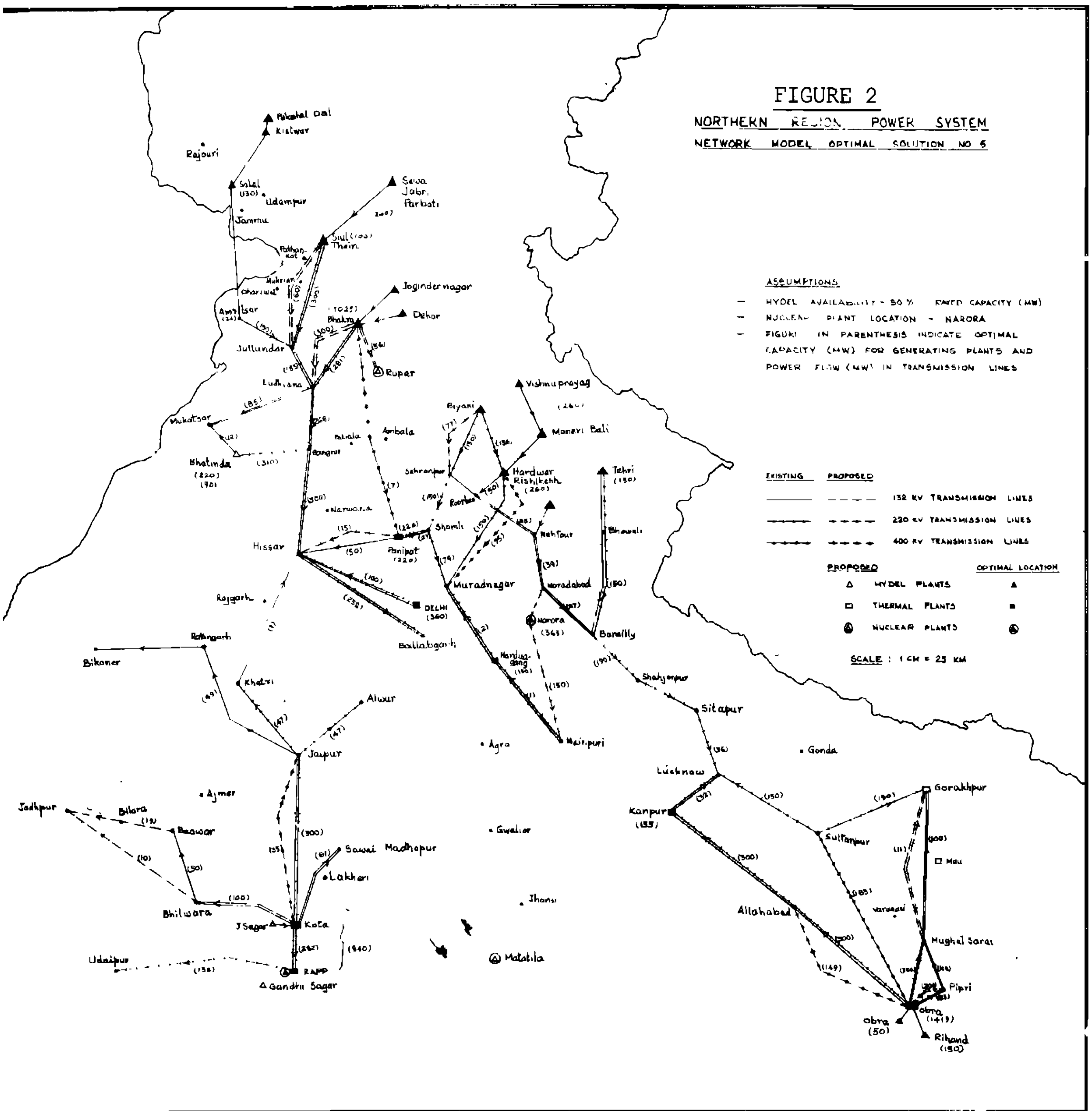
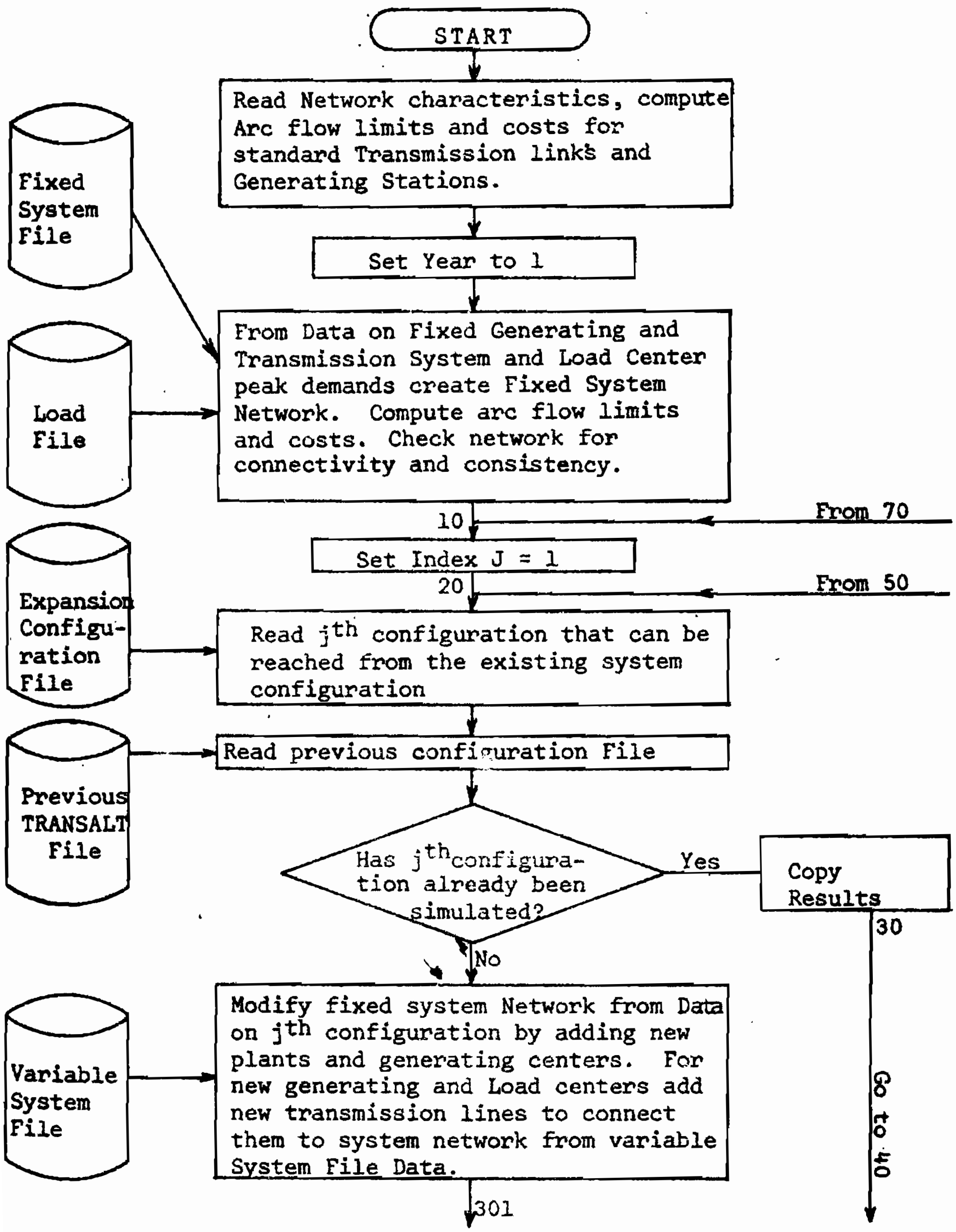
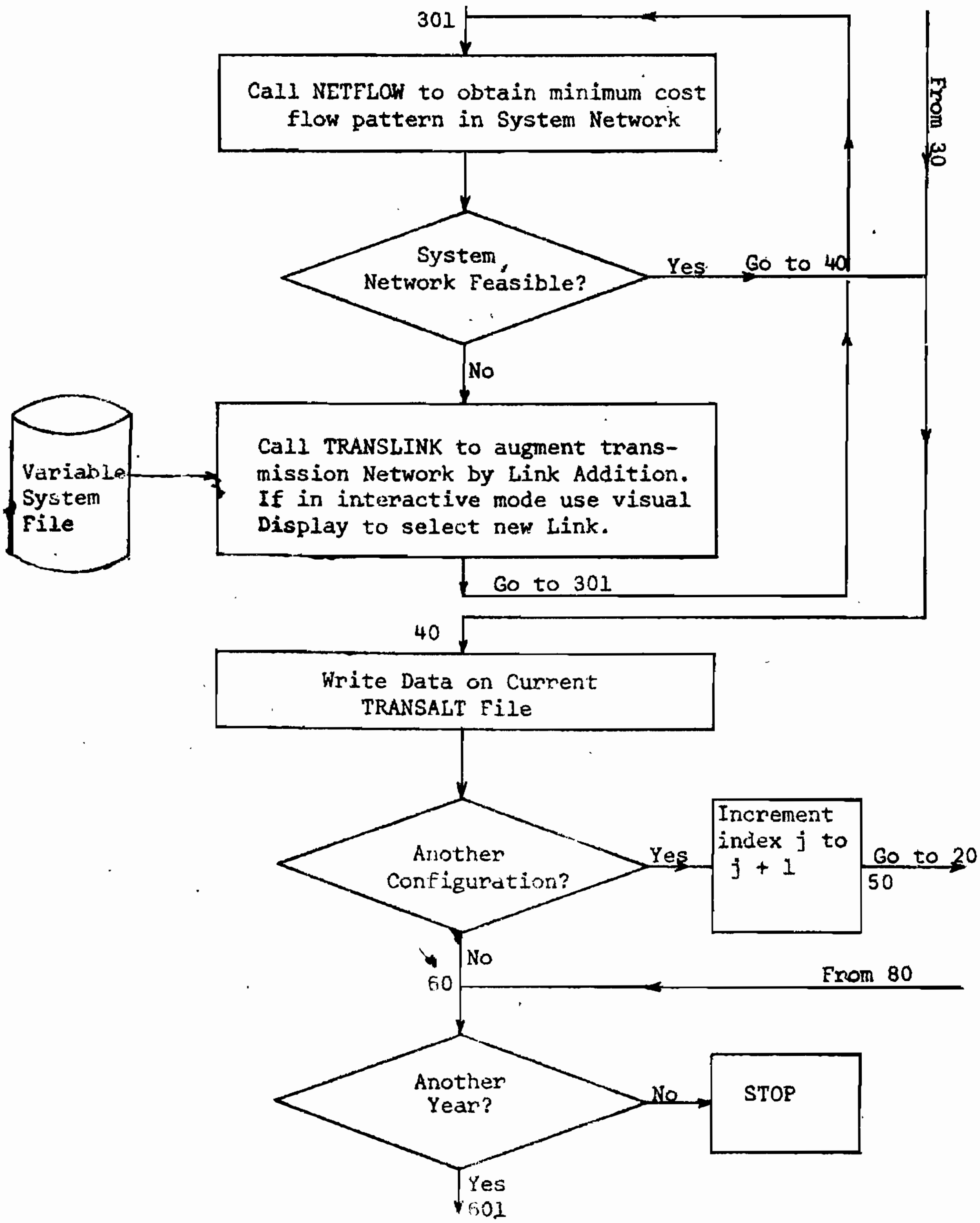
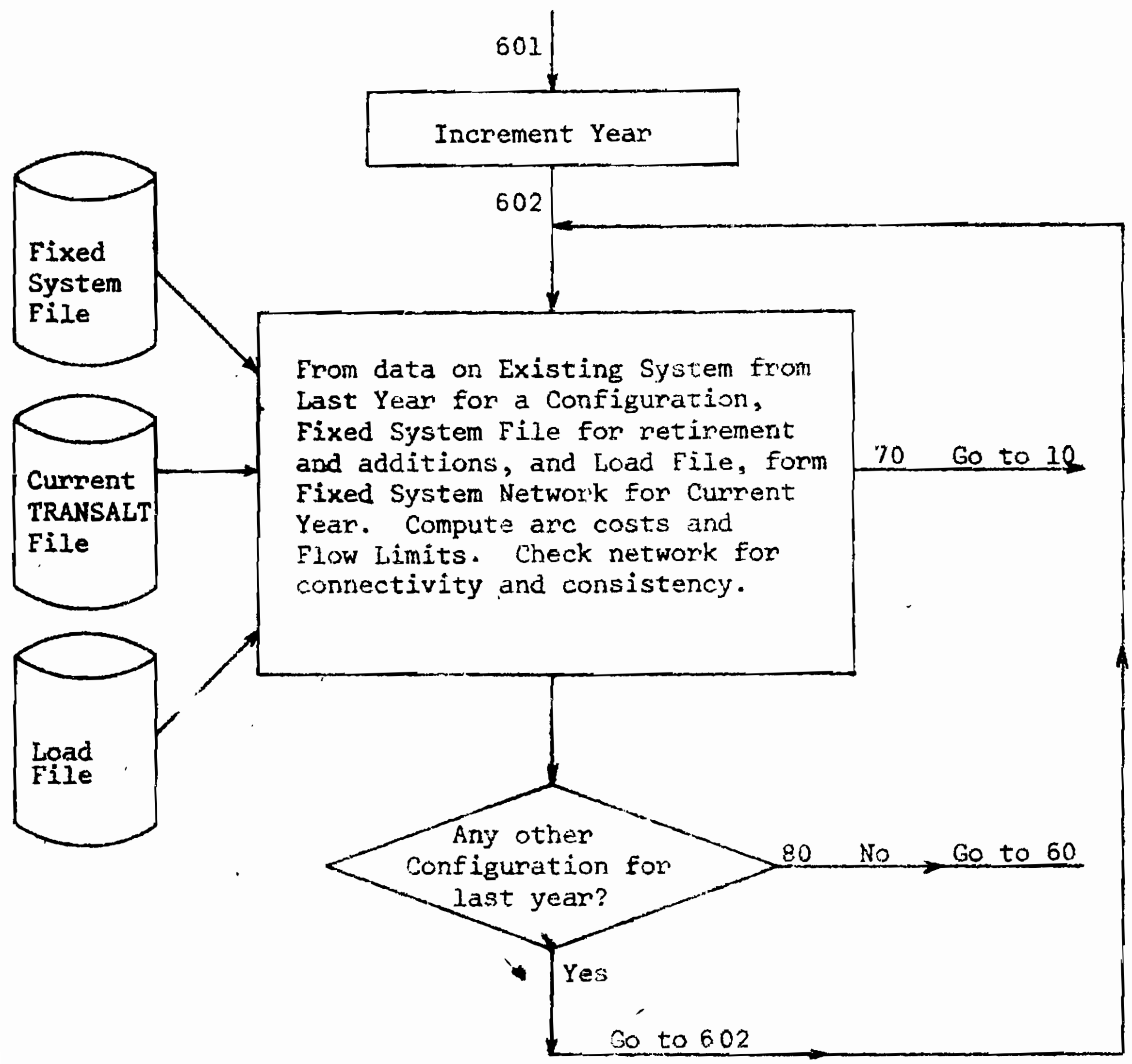


FIGURE 3. NETRAN MODULE FLOW CHART




301
Call NETFLOW to obtain minimum cost flow pattern in System Network
From 30
System Network Feasible?
Yes
Go to 40
No
Variable System File
Call TRANSLINK to augment transmission Network by Link Addition. If in interactive mode use visual Display to select new Link.
Go to 301
40
Write Data on Current TRANSALT File
Another Configuration?
Yes
Increment index j to j + 1
Go to 20
50
No
60
From 80
Another Year?
No
STOP
Yes
601


601
Increment Year
602
Fixed System File
Current TRANSALT File
Load File
From data on Existing System from Last Year for a Configuration, Fixed System File for retirement and additions, and Load File, form Fixed System Network for Current Year. Compute arc costs and Flow Limits. Check network for connectivity and consistency.
70 Go to 10
Any other Configuration for last year?
80 No Go to 60
Yes
Go to 602

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