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Production and maintenance planning for electricity generators: modeling and application to Indian power systems

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Abstract

This paper describes the development of an optimization model to perform the fuel supply, electricity generation, generator maintenance, and inter-regional transmission planning for the Northern Regional Electricity Board (NREB) of India. A review of the existing planning process of NREB revealed several areas of potential improvement. In the past, NREB did not use optimization and/or probabilistic methods in their planning. Their decision-making on maintenance, generation and fuel allocation was being performed in a sequential and 'fragmented' fashion, ignoring the possibility of interaction between the generation, transmission, and fuel supply subsystems. The deterministic treatment of outages of generators, and the planning criterion of spreading demand shortfall uniformly across the regions, were other areas of potential improvement. An integrated model, using linear programming together with a heuristic, has been developed to perform joint decision-making on fuel supply, maintenance, generation, and transmission. Monte Carlo simulation is used to incorporate the random outages of generators. The model has been prototyped using GAMS language together with a spreadsheet interface, and implemented for the NREB system. Substantial reduction in system costs is envisaged based on the results of a case study. The model is expected to aid the complex decision-making process of NREB planning engineers in several important ways.

Keywords: electric power system planning, linear programming, Monte Carlo simulation, optimal maintenance planning

Introduction

Decisions in electric power system planning

An electrical power system comprises a number of subsystems, with some activities associated with each of them. The (thermal) generating units in a power system receive fuel from the fuel supply subsystem through a network of fuel suppliers. The electrical power (measured in terms of megawatts, (MW)) produced is fed to the supply nodes of the electrical transmission network which flows on to the demand nodes. There are several decisions that an electricity planner seeks to optimize, and these decisions are intricately linked across the fuel supply, generation, and transmission subsystems. These decisions vary depending on the timeframe and could be momentary fluctuation in generation in real time to the investment decisions in long-term planning. The subject of this paper is the medium-term operations planning which typically spans several weeks or months, or up to a year. The relevant decisions include fuel supply from the fuel sources to the generating stations, MW generation at each generator, timing of maintenance of generating units for annual overhaul, and MW transmitted from various supply nodes to the demand nodes.

An overview of the Indian power sector

In India, operations planning is performed by the Regional Electricity Boards (REB) for the fuel suppliers, generators, and transmission network of their constituent states. The Indian power system has grown rapidly from 2,250 MW in 1961 to nearly 100,000 MW of installed capacity today. The electricity demand has also grown at a very high rate of over 10% annually and many parts of the country continue to face severe peak electricity shortages of the order of 20%. The electricity demand in India has both sharp seasonal trends and a very high peak/off-peak trend within a day. The transmission network has also grown over the years to form a high-voltage national grid connecting all five REBs. The primary fuel for power generation in India is coal, and it accounts for approximately 62% of the total generation. There is a well-established railway network which is used for coal haulage from the coal fields to the power stations. Hydropower is the next most important source of electricity, accounting for 28% of the total generation. REBs are entrusted with the responsibility of optimal usage of power system resources. The task is an extremely complex one because of the various operating considerations, interaction amoung various subsystems and, also because of the large number of generators for which decisions are sought.

Motivation of the present study for the NREB

The Northern Regional Electricity Board (NREB) is made up of seven Indian states. There are 238 generating units, totaling approximately 24,000 MW of installed capacity, ten sources of coal, and a massive transmission network at various voltage levels in the NREB system. NREB performs annual operations planning to meet the forecast (monthly) demand over the next year. The process looks at meeting the monthly demand for every state from the available generation capacity. NREB advises the constituent state electricity boards (SEB)s on the maintenance scheduling of generators, potential generation contribution, and fuel allocation. This plan is updated every quarter. The decisions are extremely important as any sub-optimality in the plan directly reflects in increased system costs, or even in energy shortages (or, the so-called 'unmet energy' in power-system engineering parlance). The total cost of meeting the annual demand is of the order of US$2 billion, and hence even a small percentage reduction in the total costs, achieved by improved planning procedure, is worth it. There is also an increasing awareness in the Indian electricity sector that advanced modeling and computerization/software can cut down planning efforts and lead to significantly better decisions. Ever since the Indian economy was opened to foreign investment, this trend has been very visible in the power sector. Many of the organizations have acquired sophisticated software and trained their personnel. This is a welcome development as improved planning in the power sector not only cuts down the cost of power system operation, which could be of the order of several hundred million dollars per annum, but also boosts production in other sectors of the economy through reduced shortage of electricity. It was in this spirit that the present 'scoping' study was undertaken for NREB by Power Technologies, Inc. (PTI) – India, in early 1997. The main purpose of the study was to:

a review the present planning process;
b propose potential improvements;
c demonstrate the effectiveness of such improvements using NREB system data.

Review of the NREB planning process

Lack of appropriate documentation

What seems to be a routine job in any consulting project was thwarted by the poor documentation by NREB of their planning methodology. The entire process of fuel supply, production, maintenance, and transmission scheduling was being performed on a spreadsheet on a personal computer. There was absolutely no documentation of the methodology. Our initial discussion with NREB personnel revealed that the planning methodology was very much dependent on the knowledge of modeling and computer skills of the younger people at a junior level. The senior personnel were very knowledgeable of the practical considerations, but had little involvement in mathematical model development and computer implementation. This aspect was not particularly surprising given that it almost echoed PTI experience with various other organizations in the Indian power sector. The positive aspect of the review process was that NREB was open to new ideas, and had realized that the existing methodology dealing with billions of dollars needed improvement.

Planning methodology

The methodology essentially looked at scheduling available generation (MWh) for *only the major power stations for each month*, and for each state (region). A second set of calculations is performed to check the feasibility of meeting the peak MW demand[1] *for a typical day* in each month. A power station comprises several generating units. Decisions on generation and maintenance are actually sought at a unit level rather than for the entire station because the units may vary in size, efficiency, age, etc. However, adjusting the maintenance plan manually for 238 generating units could be an extremely time-consuming and tedious process. NREB preferred to live with the assumption of arbitrarily allocating the generation of the whole station among the individual units. A plant (or power station) load factor (PLF) is applied on the available capacity to calculate the total MWh energy (i.e., available MW $\times$ number of hours in the month $\times$ PLF) that is obtainable from the unit in the whole month. The PLF is estimated by the individual power-station managers based on their expectation of the performance of the plant. The total energy supply over all units in a region (state) is added up and deducted from the forecast of the monthly energy requirement to calculate the surplus/deficit energy for the month. The available capacity is calculated for each major power station by reducing the

[1] The energy (MW-hour or MWh) requirement is specified for the whole period (e.g. month), while peak MW demand is instantaneous in nature. Both energy and peak MW demand constraints need to be satisfied.

capacity by forced (random) outage rate (FOR) and planned outage (or maintenance). The annual maintenance requirement (in days) is specified for each generating unit. The percentage reduction in capacity of the station for a typical day of a month is determined from the number of days each generating unit is put on maintenance. The capacity reduction for maintenance is a planning decision, and is achieved by varying the maintenance of various power stations manually until all states (regions) in a given month have a reasonably uniform percentage of energy shortage.

Once generation and maintenance schedules are achieved, the next stage is to allocate enough coal to the coal-based stations, from one or more mines to which they are connected, to be able to generate the required MW. If adequate coal supply cannot be ensured to all generators, the generation dispatch is re-adjusted. The relatively small storage capacity of coal at pit-head/power plant sites, as compared to the daily consumption of coal in power stations, allows very little scope to keep inventory, and such considerations are therefore aptly ignored. A power flow study is performed with the generation and demand pattern to confirm that no violation of transmission flow and voltage constraints occurs anywhere in the transmission network. In case of any serious violation, the generation (and hence maintenance) schedule of some critical generators may need to be adjusted, and the process is repeated. However, the NREB system is known to have barely any major transmission bottleneck (except under major contingency events which are not considered in the planning process), and this last stage amounts to calculating the inter-state (region) power-exchange schedule for various months. The constituent SEBs are also informed about these power trades.

Potential areas of improvement

Optimization

The most striking feature of the planning methodology is that no cost information or cost-based optimization is used at all. The generators in NREB are spread over a large geographical area and the generation costs vary from (US)$12/MWh to $50/MWh, primarily due to the high cost of transporting coal over a long distance. Models of optimal fuel and generation scheduling are abundant in the power system and the Operations Research literature. Electric utilities in the developed countries use them routinely in their planning process. As mentioned before, India is only beginning to reckon the potential for such advanced technologies. There have been a limited number of studies in the Indian context that looked at the potential of applying optimization techniques to power systems. These studies, together with a host of other production and maintenance planning models in the literature, provided the necessary impetus to probe into the development of a decision support system for NREB using linear programming (LP). A brief discussion of the key models will be presented in a following section.

Integrated framework for decision-making

A second aspect of the NREB planning process is the fragmentation of the decision-making process across the subsystems. The planning process does take into account the interaction between generation and maintenance, albeit in a limited fashion. However, the fuel supply and transmission decisions are obtained *given* a maintenance and generation plan. In the course of discussion with NREB personnel, it was apparent that they did feel there are both forward and backward linkages across the fuel, generation and transmission subsystems. However, their analysis was constrained by the lack of knowledge/appreciation of optimization theory as well as the time-consuming/tedious process of manually simulating various scenarios. Also, the absence of cost information and cost-based optimization did not allow them to compare across these scenarios in a more useful way.

This aspect also raised interesting modeling issues, namely, should the optimization span across all subsystems, or should there be a series of models for different subsystems from the upstream activities to the downstream activities. This area of research in power-system engineering literature has been discussed from time to time, but no comprehensive study has shown so far the impact of fragmenting the decision-making.

The interaction among the subsystems requires that there should be an integrated framework for decision-making. For example, during the high coal-production months of a mine, major generating units linked to it should not be scheduled for maintenance simultaneously, in order to utilize the mine's capacity effectively. Accordingly the coal linkage decisions can be streamlined based on maintenance plans. Coal supply to units on maintenance can be reduced and optimally redistributed to other units in operation during the same period. Scheduling of coal supply should be synchronized with generator operations to lower system costs. If 'too many' cheap thermal units are put on maintenance during months of low hydro energy availability, the system costs may be very high. Thus, the maintenance plan should take into account the system hydro energy availability and ensure its optimal utilization. Further, interconnected utilities/regions can coordinate their maintenance activities in such a way that during the high demand months of one utility, others may support its demand by exporting power. This leads to higher reliability of system operation. Also, the utilities with cheaper sources of power generation can generate surplus power and substitute for the generation from relatively expensive units of the other utility, thereby achieving better economy of operation. Thus, an integrated planning methodology would maximize the cost and reliability benefits for the entire system.

In summary, one could hypothesize that the fuel supply, maintenance, generation, and transmission decisions interact with each other closely, and determining these activities in sequence may lead to grossly sub-optimal results. Obviously, such interaction and the associated cost impacts are purely empirical issues, and justifying the need for an integrated (and hence more complex) model would depend upon the savings in system cost achievable. The scoping study found it worthwhile to explore the possibility of developing an integrated model and enumerate the degree of sub-optimality.

Planning criterion

As mentioned before, NREB was following a planning criterion which involved allocating energy shortages uniformly across the states for each month. In the absence of any cost information/optimization, there was no way to known if such a criterion would be in conflict with the system costs, and, if so, to what extent. NREB's view on the matter was that unless the cost impact of their planning criterion turned out to be significant, changing their current policy would face severe resistance from the states with deficit capacity.

Power system planning is inherently multi-objective in nature and a large number of criteria could potentially be used (and have been used by utilities across the globe). The most prominent among them and the relevant ones in an Indian context may include minimum system costs and expected energy shortage. A number of maintenance planning studies have also employed a third criterion, 'equalizing spare/deficit across time periods', which is similar in spirit to the one employed by NREB. A study by

London Economics (1990) recommended that 'REBs should be charged with producing overall regional maintenance plans to minimize costs while meeting projected demand'.

Given the inclination of NREB to make all states reasonably happy (through uniform allocation of energy shortages), an interesting computational approach called Compromise Programming (Zeleny, 1982) was also considered to be worth pursuing. Compromise Programming (CP) enables the planner to look for good compromises among conflicting criteria.

Probabilistic consideration of forced outage of generators

NREB performed the energy (MWh) calculation by reducing the capacity by the FOR. On the other hand, the peak MW availability calculation considered the unit to be fully available. For example, if a generating unit of 100 MW is known to have a 10% outage rate, the available capacity is assumed to be 90 MW for energy calculation, and 100 MW for peak MW calculation. Such approximation could give grossly erroneous estimates of the expected energy shortages and peak deficit, and also, thereby, result in a sub-optimal production and maintenance plan. Planning studies dealing with uncertainties associated with the availability of production facilities (i.e., either IN with probability α, or OUT with probability $1 - \alpha$) have employed the Monte Carlo simulation technique (and its variants) given its simplicity as well as the ability to handle complex situations. There were several other sources of uncertainties in the NREB system including hydro inflow uncertainties, electricity demand, availability of coal, etc, but estimates of the probability distribution were not available and, hence, could not be incorporated in the present study.

To our surprise, NREB team was somewhat skeptical about the utility of the probabilistic simulation to give better outcome as compared to their deterministic approach. This feeling has been reflected elsewhere; e.g., Hobbs (1995) stated, 'A challenge facing the OR community is to convincingly demonstrate that explicit probabilistic methods can yield superior plans, and that those methods are practical and acceptable to utilities and their regulators'. In this spirit, it was considered to be a good idea to demonstrate the workings of the Monte Carlo simulation method using NREB data and test the hypothesis that NREB's planning method gives a consistent over-estimate of the energy shortages.

Primary findings from the review

1. An LP model encompassing the above activities may be developed. There were two possibilities.

    - Develop an integrated LP model for all activities to be optimized simultaneously. This will allow all forward and backward linkages to be modeled adequately, but will also be computationally more intensive. Also, the results will be harder to interpret for such a complex model, and hence it may be more difficult for NREB to implement the plan.
    - Develop three (smaller) LPs. The first LP will decide the generation and maintenance plan for the generation subsystem. The results of this LP will be fed into a second LP which optimizes the fuel allocation, and also to a third LP which optimizes the transmission flows (to minimize losses). This will, in some way, mimic the current NREB procedure. There is, of course, a major difference that the LPs would perform cost-based optimization.

2. Extend the LP to a CP model to check

- whether there is any trade-off among system costs and the current policy of NREB to equalize the energy shortages across the states, and if so,
- whether there are good compromise solutions which give a reasonable spread of energy shortages at a small increment in system costs.

3. Extend the LP to a Monte Carlo simulation model to take into account the random generator outages.

An overview of the literature

Focus of the literature overview

The purpose of this overview is not ‘academic’ and the intent here is not to list all the works in operations planning from fuel supply to transmission, which may easily run into hundreds of articles. One can broadly categorize these into industrial/production grade models that are being used in the utilities, and published literature in the journals.

There have been successful industry applications with decades of industry-year experiences with some of the models such as WASP (International Atomic Energy Agency, Central Electricity Authority, application for India, 1983), EGEAS (Bloom, 1982; Electric Power Research Institute, CEA case study for India, 1983), PROMOD (Electric Power Research Institute, currently maintained by NewEnergy), MAPS (Stoll, 1989, General Electric), WESCOUGER (Erwin et al., 1991, maintained by ABB Power System), UFIM (Chao et al., 1989, maintained by EPRI), TOPS (Merrill, 1996, maintained by Power Technologies, Inc), OPERA (Ringeissen et al., 1996, maintained by Electricité de France), etc. An excellent review of some of these and other models in the power engineering/Operations Research/ energy literature can be found in Hobbs (1995). Although these models have become part of the planning exercises in a large number of utilities across the globe, it was not possible to use one of these ‘off-the-shelf’ models for the following reasons.

- None of these established planning models deal with *optimal* maintenance decisions. The maintenance decision is either exogenously specified, or calculated based on a simplistic ‘valley fill’ heuristic method. In the context of NREB planning, optimal maintenance decision was the key consideration. There is some literature on optimal maintenance planning models that we will discuss later on, but none of these methodologies have been integrated into the popular planning model/ software. It was concluded in a previous study (Chattopadhyay et al., 1995) that the ‘valley fill’ heuristic can lead to significantly sub-optimal solution.
- The timeframe involved in NREB planning was *medium* term whereas many of the planning models such as WASP/EGEAS are ideally suited for long-range planning dealing with *capacity expansion* decisions among other things.
- The functionality requirement for the NREB situation was demanding and encompassed practically all subsystems from fuel supply to transmission for multiple areas (SEBs). The majority of the operations planning models fall short of such requirements. While some models meet them (e.g., TOPS/OPERA), these are unable to optimize certain decisions (including maintenance), and incorporate transmission constraints.

The literature in the power-system engineering area has evolved almost independently in the following areas:

- maintenance planning to minimize/spread risk of outage;
- optimal generation dispatch with and without fuel supply optimization;
- optimal transmission dispatch, or the so-called optimal power flow.

The power system literature on maintenance planning, and especially its integration to the production (or generation) was of interest to us in the present context. The literature on optimal power flow is very well developed, and we looked at the models developed for the Indian power system that had adopted generation and transmission cooptimization for the national grid operated by the Power Grid Corporation of India Ltd (PGCIL).

Maintenance planning

Various maintenance scheduling methods have been proposed in the literature based on different criteria and mathematical programming techniques. Most of the research on maintenance planning looked solely at the risk criterion, and used either deterministic criterion, or probabilistic criterion. There has been limited research on cost-based optimization for maintenance planning.

Risk-based maintenance planning models

The levelized reserve method (Stoll, 1989) seeks to equalize the reserve (i.e., total capacity − capacity on maintenance − load) for each month of a year. Though this method has been widely used because of its simplicity, it does not incorporate the random outages of generating units. This technique, also known as the ‘valley filling’ technique, has been used in a number of power-system planning software programmes. The levelized risk method (Garver, 1972) attempts to achieve uniform loss of load probability (LOLP) (see Billinton, 1984 for a technical description of LOLP) for all months in a year. This procedure takes into account forced outage rate of the units by incorporating their effective load carrying capability. The schedule usually results in a lower annual LOLP as compared to the levelized reserve method. Incorporating LOLP in the optimization model adds significant complexity because the problem is non-convex. If LOLP is the established criterion in a system, modeling innovations to incorporate LOLP is a significant undertaking, as explored in a recent research study by Chattopadhyay and Baldick (2000). Stremel (1981) has proposed a probabilistic maintenance scheduling method for generation system planning. A continuous approximation of the equivalent load curve using the statistical cumulants of the hourly load distribution and the unit outage distribution has been used. Stremel and Jenkins (1981) have proposed an extension of the levelized risk method incorporating load forecast uncertainty in the model. Three different load conditions (expected, high, and low) are considered and a weighted risk is calculated for all demand scenarios. The corresponding equivalent load is used for maintenance scheduling. However, the method of cumulants, despite its significant computational advantages, has not been extended to transmission-constrained optimization models, and hence is of limited interest in the present context (Puntel et al., 1990; Chattopadhyay et al., 1995). Chen and Toyoda (1990; 1991) have improved the method to levelize the *incremental* risks, which ensures minimum expected energy shortage. The ‘minimum energy shortage’ criterion is of interest given its natural appeal, and we have considered this in our analysis in addition to cost and NREB's current criteria.

Cost-based optimization

Yamayee et al. (1983) have proposed an optimal maintenance scheduling method wherein production costs or unreliability costs are minimized. Their results reveal that for both production cost and unreliability cost minimization, the LOLPs are quite close. Mukherjee et al. (1991) propose a linear programming model for the scheduling problem that also considers production-cost minimization as the planning criterion and the 'risk' is modeled as an upper bound on the monthly reserves. While this research was the first that marked integration of production and maintenance for cost-based optimization, there are some missing elements.

- The fuel suppply optimization was not considered.
- There was no probabilistic consideration of forced outages.
- There was no consideration of transmission flow optimization.
- The use of continuous variables for maintenance decisions that are inherently binary in nature (e.g., IN/OUT), gave only approximate answers, including the possibility of obtaining erroneous maintenance schedules.

Prior studies on power system operations planning in India

There were some studies conducted by the Indira Gandhi Institute of Development Research (IGIDR) in India which were sponsored by various State Electricity Boards, the Indian Planning Commission and by the World Bank. These studies provided a very good base to start working on the planning model for NREB.

The study by Parikh and Deshmukh (1993) developed the first composite generation-transmission model (INGRID1) for Western and Southern India. Parikh and Chattopadhyay (1996) extended INGRID1 to include fuel supply optimization, details of individual generating units, and also implemented it for the national grid. This model, called NATGRID, can be used to develop annual operating plans for coal supply, generation dispatch for the individual generating units, inter-state power transfer, time-of-use pricing, and to perform cost–benefit analysis of transmission expansion alternatives. NATGRID does not optimize the maintenance plan, and assumes a predetermined maintenance plan as an input to the model.

Chattopadhyay et al. (1995) developed a mixed-integer programming (MIP) model which extended NATGRID to cooptimize maintenance decisions together with fuel supply, generation, and transmission. This research also looked at some of the theoretical issues, including the comparison of different maintenance planning criteria. The model was implemented for two interconnected Western India utilities. The results indicated that substantial cost saving was achievable through coordination of maintenance activities among interconnected utilities. This model did not incorporate the random outage of generators, and the LOLPs were generated by post-processing of results i.e., after the maintenance plan is optimized.

The mathematical model

The current modeling exercise is very similar in spirit to the ones conducted at IGIDR. The prior modeling exercises INGRID1, NATGRID and Chattopadhyay et al. (1995) conclusively demonstrated that the LP/MIP models provide a useful system approach to model the complex interaction across the subsystems. The last model in particular is closely related to the decision-making framework of NREB. One possibility, in fact, was to directly employ it for the NREB system. The critical factors that deterred us from employing the MIP model were,

- the size of the problem. The NREB system comprises 238 generating units. NREB needs to decide the starting and end days of a generator maintenance plan which requires a daily resolution. The MIP model will have 86,000+ binary variables and to our knowledge no commercially available MIP solver could handle such a problem within practical computational time limits;
- consideration of forced outage rates. The NREB methodology did include random outages in a crude way, and indicated that they are an important factor that should be included in the planning methodology;
- planning criterion. NREB also indicated that any deviation from their non-cost criterion of uniform allocation of energy shortages (or shortfall) across the states needs to be justified on the basis of significant cost reduction. This led to the consideration of developing a multi-objective optimization framework.

Given the difficulties associated with the mixed-integer programming model, a combination of LP with a heuristic was considered to be an alternative for the following reasons.

- The continuous (maintenance) decision variable to determine whether to put a generating unit on maintenance could be utilized to indicate the exact starting date within the broader time-step (month/week);
- LP model, being computationally less intensive compared to an MIP, is better suited for Monte Carlo simulation to take into account the random outage of generators, uncertainty in load, etc;
- The maintenance plan using LP will not necessarily be a meaningful one and a heuristic procedure has to be developed to suitably modify the initial (relaxed) LP solution to obtain a practicable maintenance plan and associated fuel supply, generation, and power transmission plans.

The computational procedure that has been developed for NREB operations planning follows the idea of solving MIP problems using Specially Ordered Set (SOS) variables. The ordering of the integer (binary) variables is obtained using a rule base that takes into account, amidst regular conditions, special restrictions that may exist on the maintenance scheduling process that are difficult to model mathematically. The implementation of the algorithm involves the following steps:

- choosing a random sample of available generators;
- solving the 'relaxed' LP model to generate an approximate maintenance plan and associated decisions;
- applying a heuristic which involves developing the maintenance plan, ordering the binary variables following certain rules;
- solving the LP again having fixed the (binary) maintenance variables to produce the associated operations decisions on fuel supply, generation, and transmission flows;

- moving onto the next random sample, and repeating the process until all samples are exhausted;
- computing the average of all random scenarios, or the expected outcome.

It should be noted that in the approach we have adopted here the forced outages are sampled first and then a maintenance plan is generated *given* the outage pattern. The idea here is to get an average/expected and *robust* maintenance plan that can deal with a large number of such outage patterns simulated using random sampling. However, it is possible to theorize a more accurate 'contingency-constrained' preventive maintenance plan that can deal with all forced outage situations *simultaneously.* Although it is not difficult to formulate such a model, the computational complexity associated with an integrated generation–transmission model is the major reason why the approach is not adopted in the present application.

We will describe the core (relaxed) LP model first, followed by the heuristic procedure, and the aspects of the second LP which differ from the first (relaxed) LP.

The linear programming model

Sets

g	all generating units which include $c(g)$ (cost-fired plants), $h(g)$ (hydro plants) and $nc(g)$ (oil- and gas-fired stations). Thermal plants $[tm(g)]$ include the coal, oil and gas-fired plants, i.e., $c(g) \cup nc(g)$
s	coal-fired power stations comprising a certain number of generating units $c(g)$
m	months
q	quarters
c	coal companies
k	grade of coal
r	transport mode
i, j	area index

Variables

$GEN_{g,m}$	Generation of unit g in each month m (MWh)
$U_{g,m}$	Availability of the units in each month (0–1). • $U = 0$ indicates that the unit is on maintenance for whole month • $U = 1$ implies the unit is 100% available for generation • $0 < U < 1$ implies that the unit is on maintenance for part of the month
$COAL_{s,c,q,k,r}$	coal production and linkage from mine c to power station s, by transport mode r, in quarter q, of grade k (tons)
$T_{i,j,m}$	MW transfers between areas (states/utilities) i and j (MW)
$EUE_{i,m}$	expected unmet energy (or, energy shortage) for area i in m (MWh)
$EUP_{i,m}$	Expected peak shortage for area i in m (MW)
$COST$	Total system operating costs (fuel production, transportation charges and in-plant costs) and energy shortage costs
VAR	Variance of expected energy shortage, or unmet energy (EUE) over the 12 months

Constraints

- generating capacity constraint
- min/max generation limits for thermal units
- hydro energy constraint for hydro units
- maintenance period constraint
- coordination constraints
- energy-balance for coal-fired units
- coal production capacity constraint
- coal linkage constraint
- monthly energy demand constraint
- transmission capacity constraint

Parameters

$DCAP_g$	the derated capacity of the unit g
HRS_m	the total number of hours in month m
θ	availability of the generator which is a random parameter. $\theta = 1$ if the unit is available, and $\theta = 0$ if it is out
K	index for the Monte Carlo simulation samples
$MAXHRS_{tm(g)}$	the maximum operating hours in a month for unit tm
$MINHRS_{tm(g)}$	the minimum operating hours in a month for unit tm
$HYDRO_{h(g),m}$	the hydro potential (MWh) for unit h in month m
$MINMON_g$	the earliest date by which the unit can be scheduled, e.g., 1.2 indicates 6th day in second month of the planning period
$MAXMON_g$	the last date by which the unit must be scheduled, e.g., 4.5 indicates 15th day in the fifth month of the planning period
$t_g(m)$	the range of days between these two limits
$MAINT_g$	the number of months required for maintenance operations for unit g. This could be a fraction as well, e.g., 0.8 months.
$UNIT_s$	the number of generating units in station s
$E_{c(g)}$	the overall thermal efficiency of the unit $c(g)$
CAL_k	the calorific value of k-th grade coal in MCal/ton
B	coefficient for conversion (1 MWh = 857 Mcal)
$MINECAP_{c,q,k}$	mine production capacity of k-th grade coal for mine c in quarter q in tons
$LINKAGE_{s,c,q,r}$	capacity (tons) of the link between mine c and station s along transport mode r for quarter q
$ENERGY_{i,m}$	the total MWh requirement for i-th area in month m
$TRANCAP_{i,j}$	the total MW-transmission capacity of all lines between areas i and j
$SCOST_{nc(g)}$	generating cost of oil- and gas-fired stations (Rs/MWh)
$NCF_{c(g)}$	non-fuel costs for coal-based generating units (Rs/MWh)
$TRCOST_r$	coal transportation charges by transport mode r (Rs/ton/km)
$DIST_{s,c,r}$	distance of s from coal mine c by transport mode r (km)
$MCOST_{c,k}$	mine-mouth cost of coal of mine c grade k (Rs/ton)
$UECOST_{i,m}$	energy shortage cost for state i in month m.
EUE_i	the average annual energy shortage for area i

$PEAK_{i,m}$	the month m peak demand for area i
$UFIX_{g,m}$	parameter; 1 if $U_{g,m} > 0$, and 0 if $U_{g,m} = 0$
$EUP_{i,m}$	expected unmet peak demand of area i in month m
w_1, w_2	the weights on the squared deviation and absolute level of energy shortage
W_{VAR}, W_{COST}	the weights on the *VAR* and *COST* objectives respectively.

Mathematical formulations of the constraints and objective functions are described next.

Generating capacity constraint
The available generation from a unit is constrained by the availability of the generator net of maintenance and forced outages. The maintenance (or planned) outage is a decision variable determined endogenously, while the forced outage is uncertain and modeled using random samples of outage conditions.

$$(GEN)_{g,m} \leqslant U_{g,m}.(DCAP)_g.(HRS)_m.\theta^K$$

Min/max generation limits for thermal units
NREB indicated that there are often restrictions on the maximum generation that may be obtained from a coal-based generator. These limits are expressed in terms of the minimum and maximum number of hours by the power station managers.

$$(GEN)_{tm(g),m} \leqslant U_{tm(g),m}.(MAXHRS)_{tm(g)}.(DCAP)_{tm(g)}$$

$$(GEN)_{tm(g),m} \geqslant U_{tm(g),m}.(MINHRS)_{tm(g)}.(DCAP)_{tm(g)}$$

Hydro energy constraint for hydro units
Hydropower generation is limited by the total hydro energy available. These constraints are applicable for hydro units with reservoir storage. There are more severe restrictions on the run-of-the-river type plants which are in the form of fixing the generation dispatch to the energy availability as these plants do not have any choice on 'when to generate'. The constraint for reservoir-type hydro units is defined as,

$$.(GEN)_{h(g),m} \leqslant (HYDRO)_{h(g),m}.U_{h(g),m}$$

Maintenance period constraint
The maintenance of generating units usually has some flexibility. A generating unit can go into maintenance beyond some months since the last maintenance, and it must go on maintenance before it gets damaged due to over-usage.

$$\sum_{t_g(m)} U_{g,t_g(m)} \leqslant MAXMON_g - MINMON_g - MAINT_g$$

Coordination constraints
NREB observed that there could be additional restrictions on the maintenance process such as not scheduling all the units in a station simultaneously.

$$\sum_{g \in s} U_{g,m} \leqslant (UNIT)_s - 1$$

Energy-balance for coal-based units

The physical energy (calorie) balance states that the coal-fired units can generate only so much electricity as dictated by the efficiency of the power plant, calorific content of the fuel, and the quantity of coal that it receives. This balance equation basically links the fuel supply, and the generation subsystems.

$$\sum_{r,k,c} COAL_{s,c,q,k,r}.E_{c(g)}.CAL_k = \sum_{c(g)\in s} \sum_{m\in q} \sum_{c} GEN_{c(g),m}.B$$

Coal production capacity constraint

The production of coal is constrained by the forecast of capacity of coal mines. The Coal Linkage Committee provides this information to NREB on a quarterly basis.

$$\sum_{s,r} (COAL)_{s,c,q,k,r} \leqslant (MINECAP)_{c,q,k}$$

Coal linkage constraint

The haulage of coal from a mine to a power station is also constrained by the transportation capacity. This information, again, is supplied by the Coal Linkage Committee to NREB. This linkage capacity is exogenously determined by the Coal Linkage Committee, taking into account all factors affecting the transportation of coal, e.g., congestion on some of the critical railway corridors, coal-storage capacity, etc. While these linkage capacities may potentially have a significant bearing on the overall system costs, the present model assumes these parameters as *given*, primarily because the decisions on these are not within the purview of NREB, and also because this simplifies the model.

$$\sum_{k} (COAL)_{s,c,q,k,r} \leqslant LINKAGE_{s,c,q,r}$$

Monthly energy demand constraint

The monthly energy requirement for each state in each month must be met either from its own resources, or by importing from other states (net of losses). Any shortfall in demand for each randomly generated scenario is averaged over all scenarios to calculate the expected energy shortage. The energy shortage for each scenario is penalized in the objective function by the cost of unmet energy. The energy balance equation holds the generation and transmission subsystems together.

$$\sum_{g\in i} (GEN)_{g,m} + \sum_{j} T_{i,j,m}.(1 - LOSS_{i,j}).(HRS)_m = (ENERGY)_{i,m} + (EUE)_{i,m}$$

Transmission capacity constraint

The inter-state transmission of power is constrained by the physical capacity of the line, or by some other transmission phenomenon, e.g., stability limit, voltage limit, etc. The calculation of these limits may be a complex undertaking in itself, but NREB has had plenty of experience with system planning and was able to provide the inter-state transfer limits.

$$T_{i,j,m} \leqslant (TRANCAP)_{i,j} \qquad \forall m$$

Cost objective function

The cost objective function or the total system cost (*COST*) can be expressed mathematically as,

$$\sum_{ncg,m}(GEN)_{ncg,m}.SCOST_{ncg} + \sum_{cg,m}(GEN)_{cg,m}.NFC_{cg} + \sum_{s,q,c,k,r}(COAL)_{s,c,q,k,r}.[TRCOST_r.DIST_{s,c,r}]$$

$$+ \sum_{s,c,q,k,r}(COAL)_{s,c,q,k,r}.(MCOST)_{c,k} + \sum_{i,m}(EUE)_{i,m}.(UECOST)_{i,m} = COST$$

The coal transportation costs are specified on a per ton/km basis, which is the norm followed by the Indian Railways for supplying coal to the power sector (London Economics, 1990). Hydro-power generation costs are relatively minor in the NREB system and are ignored.

Equalizing the energy shortage across the states

In order to mimic the current NREB process of allocating the energy shortage across the states as uniformly as feasible, a second objective function of minimizing the variance of expected energy shortage (*VAR*) is also considered using the following formula:

$$w_1\sum_{i,m}[EUE_{i,m} - EUE_i^*]^2 + w_2\sum_i(EUE_i^*)^2 = VAR$$

The *VAR* objective function requires a quadratic LP formulation which is as robust and simple as the LP technique. The reason *VAR* is considered is to check the production cost and energy shortage impact of the criterion chosen by the NREB in developing maintenance plans. Although the NREB objective of equal energy shortage could be achieved in theory using a simpler linear constraint, the discrete nature of the unit sizes in practically all cases implied that this constraint can be satisfied rarely. The *VAR* objective overcomes this problem, and also provides a good performance measure of the overall maintenance plan.

Compromise programming formulation

An interesting formulation of the multi-objective problem was proposed by Zeleny (1982). The so-called Compromise Programming (CP) approach looks at a composite objective function which comprises the individual objective functions (Z_p) and an 'ideal solution' (Z_p^*), where $p = 1, \ldots N$ are the objective functions. The ideal solution is nothing but the collection of the individual optimal solutions obtained by solving for each objective function p independently. An ideal solution is usually not feasible because all the individual optimal solutions may not be achievable simultaneously due to the trade-off among the objectives. The composite objective function, termed as the distance functions, aims at locating the best compromise solution by minimizing the distance of the feasibility frontier from the ideal solution.

In the present context of NREB operations planning, the following compromise objective function has been adopted,

$$DISTANCE = W_{COST}.(COST - Min\ COST)/Min\ COST + W_{VAR}.(VAR - Min\ VAR)/Min\ VAR$$

which simplifies to,

$$DISTANCE = W_{COST}.COST/Min\ COST + W_{VAR}.VAR/Min\ VAR - Constant$$

The *DISTANCE* criterion could be minimized having obtained the individual *COST* and *VAR* minimizing solutions. The constraints of the CP problem are same as the original *COST* or *VAR* minimization problem. The compromise solution would indicate the trade-off among the objectives, and also, whether there are good compromise solutions that may help NREB achieve reasonably uniform distribution of energy shortage at a modest increase in cost.

The heuristic to order the binary variables

The maintenance plan, determined by the LP model, may not be realistic for one or more of the following reasons.

- *Impracticable unit maintenance plans*. NREB indicated that the maintenance work requires a continuous stream of days allocated to a unit, rather than two, or more, blocks of days being allocated for partial maintenance work. The LP, in itself, cannot ensure that the maintenance plan will comprise a continuous series of days allocated to a particular unit.
- *Not satisfying peak demand*. Even though all the unit-wise maintenance plans are valid, and the monthly energy demand constraints are satisfied, it may so happen that the monthly peak demand constraint is not satisfied. The peak demand constraint requires that the total MW generation capacity available in a state is greater than, or equal to, the (forecast) monthly peak. The peak demand constraints cannot be represented without the use of binary variables.

To overcome this, a three-stage procedure is adopted, in which a set of rules is applied on the initial maintenance plan to make it a valid one, and then feeding the plan to a second LP model. At this stage the values of availability of generators U are known, and the peak demand constraints are included. The optimal levels of the generation, fuel supply, and transmission flow variables (i.e., *GEN*, *COAL*, and *T*) obtained from the second LP, thus, assures practicability of the maintenance plan, as well as taking into account the peak demand constraint.

Following are the steps in the heuristic to post-process the initial LP solution and, thereby, order the maintenance variables (which are nothing but $[1 - U_{g,m}]$ where $U_{g,m}$ is the availability of the unit) for each unit:

Step 1: For each generating unit maintenance plan $M_{g,m} = [1 - U_{g,m}]$, identify the position of the non-zero elements. Define $M1_{g,m} \in M_{g,m}$ with the subset of elements between the first and the last non-zero elements;

`Example: Consider a one month maintenance plan spread over a six-month planing horizon for a generating unit represented by the vector` $M_{g,m}$`: [0.1 0 0.4 0.3 0.2 0]. The vector` $M1_{g,m}$ `will be the subset: [0.1 0 0.4 0.3 0.2] i.e., the subset of elements between the first and last non-zero elements. We will continue discussing this example for the subsequent steps.`

Step 2: Check if there are zeroes in between the elements of $M1_{g,m}$,

If yes, go to Step 4,

Otherwise proceed to Step 3;

Continuing with the example, since there is a zero element in the set $M1_{g,m}$, Step 3 will be followed next.

Step 3: Check the total number of consecutive non-zero elements each less than one (say H_g),
If $H_g \leqslant 2$, the maintenance plan is valid (say $M^*_{g,m}$) and is passed, or,
If $H_g > 2$ and all consecutive elements between the first and last elements of $M1_{g,m}$, equal one, the maintenance plan is also valid ($M^*_{g,m}$) and passed, *STOP*,
Otherwise proceed to Step 4;

In the present example, $H_g = 3$, and also the second criterion is not satisfied, hence we will proceed to Step 4.

Step 4: Choose the largest element M_g^{MAX} in $M1_{g,m}$,
If there is a conflict among two or more equal numbers, select the one that has the highest ordinal rank:

Here, $M_g^{MAX} = 0.4$.

Step 5: Calculate the parameter $C_g = MAINT_g - M_g^{MAX}$, which is the residual maintenance requirement after deducting the largest element from total maintenance requirement.
If $C_g \leqslant 1$, form a valid maintenance plan ($M^*_{g,m}$) either starting or ending with M_g^{MAX} depending upon the distribution of the elements of $M1_{g,m}$ around the M_g^{MAX}. If the elements the sum of which forms the higher fraction of C_g are on the left-hand side of the M_g^{MAX} element, $M^*_{g,m}$ will *start* with M^{MAX}. If the elements the sum of which forms the higher fraction of C_g are on the right-hand side of the M_g^{MAX} element, $M^*_{g,m}$ will *end* with M^{MAX}.
If $C_g > 1$, form a vector $M2_{g,m}$ with number of elements $= [C_g] + 1$, with each intermediate element being one, except the first or last element being a fraction;

The residual maintenance requirement, $C_g = MAINT_g - M_g^{MAX} = 1 - 0.4 = 0.6$. The residual requirement has the same unit as that of specifying maintenance requirement $MAINT_g$, i.e., number of months/weeks. A valid maintenance plan can now be formed *starting* with M_g^{MAX} because the sume of the elements on the right-hand side of $C_g = 0.3 + 0.2 = 0.5$ which forms the higher fraction $(= 0.5/0.6)$ of C_g as compared to the ones on the left-hand side. Hence, the valid mainteance plan is obtained as $M^*_{g,m} = [0\ \ 0\ \ 0.4\ \ 0.6\ \ 0\ \ 0]$. *STOP*.

Step 6: If M_g^{MAX} is the first element of $M1_{g,m}$, the last element of $M2_{g,m}$ is a fraction. A valid maintenance plan $M^*_{g,m}$ is obtained with M_g^{MAX} as the first element and other elements being that of $M2_{g,m}$, STOP.
Otherwise, proceed to Step 7;

For example, if the residual requirement is 5.4, we can form the vector $M2_{g,m}$: $[0.4\ \ 1\ \ 1\ \ 1\ \ 1\ \ 1]$

Step 7: If the number of elements in $M2_{g,m} >$ (Ordinal Rank of $M_g^{MAX} - MINMON_g$), again $M^*_{g,m}$ is obtained with M_g^{MAX} as the first element, followed by the elements of $M2_{g,m}$,
Otherwise, $M^*_{g,m}$ is formed with $M2_{g,m}$ elements preceding M_g^{MAX} (the first element of $M2_{g,m}$ being the fractional element, now); STOP.

For example, if the M_g^{MAX} were the 7th element, and $MINMON_g$ for the unit were 2, the number of elements in $M2_{g,m} = [5.4]+1 = 5+1 = 6$, which is $>$ $(7-2=)$ 5. The valid maintenance plan in this case will be obtained as [1 1 1 1 1 0.4].

A detailed explanation of the steps and the theoretical properties of the heuristics are beyond the scope of this paper and will be discussed in the follow-up paper (Chattopadhyay, forthcoming) that deals with these and additional complexities such as unit commitment and AC power flow constraints. Clearly, the valid maintenance plan does not ensure optimality of the LP problem any more, nor does it ensure optimality of the MIP problem. There are two reasons why the heuristic is used despite the fact that it could lead to a sub-optimal solution.

- The MIP problem is computationally very expensive.
- NREB mentioned that the maintenance plan is not simply governed by the set of logical constraints defined in the LP, but there are a few other aspects that they need to look at before deciding the plan. The present heuristic can be extended to capture these practical features such as the expiry of boiler inspection license of generating units, regulatory compliance, qualitative judgement based on the experience of maintenance planner, etc.

The second LP to obtain the final operations plan

Having obtained the maintenance plan U^* using the heuristic, the associated generation, fuel supply, and transmission variables are to be optimized again to minimize the planning criterion (*COST*/*VAR*). This second LP has two differences as compared to the first (relaxed) LP.

- The maintenance variables (U) is fixed at U^*; all the maintenance related constraints are dropped;
- peak demand constraint and associated violation variables (as defined below) are added.

Monthly peak demand constraint
Capacity available after scheduling certain number of units plus the net import (import−export) from all other areas must be adequate to meet the maximum demand in each month for all areas.

$$\sum_{g\in i} DCAP_g.UFIX_{g,m} + \sum_j T_{i,j,m}.(1 - LOSS_{i,j}) = (PEAK)_{i,m} + EUP_{i,m}$$

This constraint implicitly assumes a unit to be unavailable during the occurrence of the peak-load condition even if it is on maintenance for a small fraction of time. This may be a conservative assumption and can be modified by setting *UFIX* to 0 only if $U^*_{g,m} < \lambda$ and to 1 if $U^*_{g,m} > \lambda$, i.e., as if peak-load condition is not expected to occur during the (small) $100\lambda\%$ of the time in the month.

Computational considerations for the second LP
The second LP will typically have a lower number of variables and constraints. This is because the

maintenance variables and constraints for all generating units are removed. There are additional peak demand constraint and the associated violation variables. Nevertheless, these apply for each state, rather than for each unit. Thus, the second LP has a smaller number of variables and constraints as compared to the relaxed LP. Further, the revised optimal solution may not be far away from the first (relaxed) LP solution. Thus, the solution time for the second LP could be improved by utilizing the advanced basis matrix of the relaxed LP problem. Some of the unit maintenance plans may already be valid ones and even post-processing of others may not significantly change the energy shortage and total system cost for a practical system. All these are empirical issues which leave scope for performance improvement.

Computational scheme

Finally, the overall computation for each random sample of Monte Carlo simulation is summarized.

1. Solve the first (relaxed) LP problem and store the basis matrix.
   A first cut maintenance plan is obtained (U)
2. Use the heuristic to order the maintenance variables (U);
   Final maintenance plan (U^*) is obtained.
3. Set *UFIX* as the availability of the units (1 or 0) after taking into account the maintenance outages. Add peak demand constraints and violation variables. Drop maintenance-related constraints and variables. Solve the second LP model starting from the advanced basis of the relaxed LP solution.
   Final, generation, fuel, and power transfer plans are obtained.

Computer implementation

The scoping study involved developing a prototype and implementing the above computational scheme using a set of data supplied by NREB. The prototype was developed using the General Algebraic Modeling System (GAMS). The data input/output is handled through a spreadsheet interface. The prototype model performs the following operations.

- Reads the data from the spreadsheet.
- Sets up a large number of random samples (say, 500 to 1000 depending on the percentage level of confidence of the *COST*/*VAR* desired).
- Solves the relaxed LP, applies the heuristic, solves the second LP for each of the samples.
- Computes the average maintenance for all random samples.
- Applies the heuristic again because the average maintenance plan may not be a valid one.
- Solves the second LP given the final maintenance plan to compute the expected generation, fuel supply, and transmission flows, and the associated expected *COST* and *VAR*.
- Writes the results back to the spreadsheet.

Discussion of key results

The case study for NREB was performed in early 1997 for the period January–June 1997. The NREB plan and the background data were obtained from NREB's planning report (NREB, 1997). However, a number of additional data including cost information, parameters of the maintenance constraints, etc.

were to be obtained from other sources. NREB helped us to gather all the information by handing out a questionnaire to the power plant managers. The results of the study were presented in a forum of NREB personnel and all the plant managers.

A direct comparison of the least cost plan obtained using the present model, and the NREB plan did not seem appropriate because the NREB plan was performed only for the major *stations* whereas the present case study deals with all generating *units* in the system. It was not possible to employ the NREB methodology for all generating units, which would involve manually adjusting the maintenance plan for all 238 generating units to ensure a uniform allocation of energy shortage across the states. The purpose, instead, is to focus on the thrust areas where the planning methodology could be improved. Cost-based optimization in itself, is a major improvement. We understand based on the prior study (Chattopadhyay et al., 1995) that such cost savings are potentially very significant. Our focus here, however, is not to estimate how much NREB could save by switching to the least cost plan, rather to determine:

- what is the cost impact of fragmenting the decision-making process?
- is there a good compromise between cost and ‘equalize energy shortage’ planning criteria?
- does NREB report an overestimate of the expected energy shortage?

Integrated versus fragmented model

A limited number of tests were conducted with the NREB database to see the cost impact of fragmenting the decision-making process. We do *not* make an attempt here to compare the NREB methodology with the proposed integrated model. The NREB methodology does not minimize *COST*, or for that matter, did not perform any optimization. The purpose of these experiments is to compare two cost-based optimization methods namely, a simpler model that uses three ‘smaller’ LPs for each subsystem vis-à-vis a ‘bigger’ integrated model. More specifically, the *COST* objective function for the following models were compared.

- *Fragmented model*. Develop the maintenance and production plan first using an LP. Then, use a second LP to generate the fuel supply plan, and a third LP to optimize the transmission flows to minimize the losses.
- *Integrated model*. The proposed model that optimizes maintenance, generation, fuel supply, and transmission flows in an integrated framework.

The difference in cost for the six-month period is observed to be Rs 4,470 million (US$100 million, 1 US$ = Rs 44 approx) which is about 10% of total system costs. The integrated model produces a significantly better plan because it can utilize the fuel and transmission resources better. The fragmented approach pre-fixes the generation and maintenance plans while optimizing the fuel supply and transmission flows. Thus, the latter approach overlooks several opportunities to lower system costs by linking fuel sources to closer coal mines, and further transferring power to states having expensive generators.

This potential saving in system costs provides an incentive to pursue the development of an integrated model for NREB.

Computational statistics

The model is solved on a Pentium m/c with 266 MHz processor. The model in its present version has over 3000 constraints and 5000 variables (of which the maintenance variables are about 1400). The relaxed LP takes approximately 45 seconds, while the heuristic takes only one second and the second LP takes three seconds. Significant order of reduction in computational time is achieved from first LP to the second LP, as has been discussed earlier. Observing the variation in system cost is also important to see if the heuristic led to a significant change in the objective function. The first (relaxed) LP produces an optimal solution of 42 158 (in Rsm) and the associated energy shortage is 4611 gigawatt hours (GWh). After the heuristic modifies the maintenance plan M and the second LP optimizes the system operation given the valid maintenance plan M^*, the second LP solution is 44 061 and the associated energy shortage rises to 5064 GWh. Thus, the *COST* has increased only by 4.3% after ordering the maintenance variables. It is possible that an MIP model would be able to locate a better integer solution and, thereby, provide an optimal maintenance plan which has a lower level of *COST.* In other words, the possibility of the current solution being sub-optimal cannot be ruled out. However, the massive number of binary variables for the MIP model (with daily resolution, i.e., 183 time steps as compared to six monthly time steps in the present LP model) prohibit us from solving the equivalent MIP model. The order of cost increase from the relaxed LP to the second LP never exceeded 5% limit for a wide range of scenarios that was run for the NREB system. This gave us a reasonable amount of confidence that the degree of sub-optimality, if any, is not high enough to forego the substantial computational advantage the heuristic provides.

Planning criterion

In Table 1, the results for the following four cases are presented.

- Minimum system cost, i.e., *COST*, or the result of cost-based optimization.
- Minimum variance of energy shortage across the states and added over six months, i.e., *VAR*. This case tries to simulate the NREB planning methodology. The results were, however, not directly comparable with the plan developed by NREB for the period, because NREB performs maintenance planning only for the major power stations, and the manual process of adjusting the maintenance plan to reduce variance may fail to locate the optimal (i.e., minimum variance) solution. We did

Table 1
Choice of planning criterion

Objective function	Minimize			
	COST	*VAR*	*EUE*	*DISTANCE*
COST (Rsm)	44,061	50,389	45,803	1.3794
VAR (GWh^2)	924,513	388,542	1,090,592	0.6121
EUE (GWh)	5,064	6,109	4,982	1.8464
DISTANCE	46,812	542,134	5,785	0.4577

notice, though, a close match of the maintenance plans for the larger generating units across this case and the NREB plan.

- Minimum total expected unmet energy (*EUE*). This non-cost planning criterion has *not* been considered by NREB as such, but has been cited in the literature (e.g., Chen and Toyoda, 1990; 1991; Mukerjee et al., 1991).
- Minimum distance, i.e., the compromise between *COST* and *VAR*. We assumed equal weights of 1 on both objective functions. This basically implies that the minimand is the sum of fractional deviation from the minimum *COST* and *VAR* objectives.

The maintenance, generation, fuel supply, and transmission flows vary widely across the four scenarios. In particular, the maintenance plans of most major generating stations varied a great deal. Let us consider first the single criterion optimization cases only (i.e., the first three rows). If we do not consider the possibility of a compromise solution, the minimum *COST* scenario is the most attractive one with lowest cost, only marginally higher total expected energy shortage and an intermediate level of *VAR*. One interesting implication of comparing *COST* and *VAR* scenarios is that the minimization of *VAR* is achieved at a rather high cost of $50{,}389 - 44{,}061 =$ Rsm 6328 (US$143m). The variation of total energy shortage over the months (Table 2) gives a better insight into the nature of the maintenance plans obtained in the two cases.

The variation of total *EUE* is quite sharp in the minimum *COST* case, but results in better economy (14% lower cost compared to minimum *VAR*) and reliability (20% lower *EUE* compared to minimum *VAR*).[2] The minimum *VAR* case provides a much smoother variation of energy shortage both across the months, as well as across the states for each month (not shown in the table). The question is whether it is worth foregoing the significant economic and reliability benefits for the sake of uniformly allocating the energy shortage across the states. NREB felt that there would be strong resistance against any operations plan that has high *VAR* associated with it. This is what brings us to the next issue of looking at the compromise solution (i.e., minimum *DISTANCE*).

Table 2
Variation of *EUE* over six months

	Total *EUE* in GWh	
Month (1997)	Min *COST*	Min *VAR*
January	846	1042
February	1535	1165
March	1318	1138
April	853	936
May	254	860
June	258	968
Total	5064	6109

[2] The *VAR* objective function includes a weight on the absolute level of *EUE* which may be increased to reduce *EUE*. In the limit, the weight w_g may be set to zero such that the minimization of variance is ignored altogether.

The minimum *DISTANCE* is obtained as 0.4577 (45.8%) which is basically the sum of the 6.2% increase over *COST*, and 39.6% increase over minimum *VAR*. It should be noted that the ideal solution in this case is nothing but [minimum *COST*, minimum *VAR*], and it is not feasible, i.e., no maintenance/production plan can achieve the two simultaneously. The compromise solution has achieved a 41% lower *VAR* at a modest increase of system *COST* by 6.2%. This solution, in NREB's opinion, was more attractive compared to the least *COST* option.

Probabilistic consideration

As explained before, the core LP is embedded within a Monte Carlo simulation scheme wherein random samples for the unit availability (i.e., parameter θ) are generated and the LP is run for each such realization. Depending upon the desired degree of accuracy of the total cost estimate, the number of samples is determined. The number of samples can be very high for a reasonable degree of accuracy e.g., 1%. Once all the LP runs are accomplished, the expected outcome (cost, energy shortages, etc.) is determined by averaging over all the LP solutions for all samples. This, in contrast to the NREB's existing deterministic methodology, allows a substantially better representation of the underlying uncertainty. The integrated model used a high number of simulations to arrive at the expected energy shortage and system costs. A comparison of the estimates of *EUE* obtained from the Monte Carlo simulation with the estimate of the NREB based on deterministic treatment of forced outage rates shows the latter leads to a highly pessimistic estimate of the energy shortage by a margin of approximately 10%. Since NREB performs a different planning criterion, and also does not optimize the transmission flows, it is not entirely appropriate to compare the two estimates. Nevertheless, the *expected* energy shortage obtained from averaging out a large number of such samples is a better estimate than that obtained using the deterministic approach. The Monte Carlo simulation runs exhibited the wide variation of total energy shortage from 4000 GWh to 5300 GWh.

The Monte Carlo simulation method is computationally intensive and the enumeration of all samples for the NREB system takes several hours even for a modest tolerance on the variance of system cost. One possible area of improvement that could be undertaken to reduce the number of samples is to use a variance reduction technique such as the one adopted in EPRI's reliability model (Pereira and Pinto, 1992) and also implemented in an extended version of the present model (Chattopadhyay, forthcoming).

Concluding remarks

This paper discusses the development of an LP-based integrated operations planning model for the Northern Regional Electricity Board (NREB) of India. This is an outcome of a scoping study that was undertaken by Power Technologies, Inc. – India, a leading international power system consulting group. NREB manages the operation of a 24 GW northern regional power system. The total annual cost incurred by the system is of the order of US$2 billion. The study involved reviewing the operations planning procedure of NREB, suggesting improvements, and demonstrating the effectiveness of such improvements.

The review process was tedious in the absence of appropriate documentation by NREB of their planning methodology, but eventually revealed several areas where the methodology could be improved. NREB's operations planning could be improved vastly by introducing cost-based optimization. The nature of interaction across various activities raised interesting modeling issues. It was observed that NREB uses a deterministic approach to deal with random outage of generators which tends to overestimate the energy shortages significantly. The planning criterion employed by NREB was to allocate the energy shortages across the regions uniformly, and it was of interest to them to see the cost implication of following such a criterion. Finally, NREB found the manual process of deriving the maintenance schedule to allocate the energy shortage uniformly a tedious and frustrating affair.

The prior modeling exercises carried out by the IGIDR, an Indian institute, provided a good starting point. A previous study developed a mixed-integer programming (MIP) model that fits well into the scope of planning decisions sought by NREB. However, several practical considerations rendered that MIP model to be unworkable. A combination of LP with a heuristic to develop the maintenance plan is considered to be a good compromise between accuracy and computational practicability. The three-step computational scheme proposed in the paper involves solving the relaxed LP, ordering the (binary) maintenance variables using a heuristic, and solving the continuous LP having fixed the mantenance plan. The Monte Carlo simulation technique is used to incorporate the random outages of generators.

The model is prototyped using GAMS language and implemented for the NREB system. The key findings of the case study include the following.

- There is significant scope for improving the operations plan through cost-based optimization and probabilistic simulation. A direct comparison of the least cost plan obtained using the present model, and the NREB plan did not seem appropriate and we focused instead on some of the modeling issues as described below.
- Even if cost-based optimization is adopted by NREB, the fragmented decision-making process currently followed by NREB leaves substantial scope for improving the plan by taking into account the interaction across the fuel supply, generation, and transmission subsystems. The cost saving is of the order of US$100m for the present case study.
- It is important to study the cost impact of NREB's current planning criterion. The case study results show that the current policy of uniformly allocating the energy shortages may be coming at a rather higher cost of approximately US$143m for the present case study. NREB could also seek a balance between their current policy of satisfying every state and minimizing the system operations costs. The case study also indicates that there appears to be good compromise solutions.
- NREB's treatment of forced outage rates leads to gross overestimation of energy shortages. The expected energy shortage figures derived from the Monte Carlo simulation run gave a much better picture of the demand/supply situation than NREB had reported.

On the whole, the scoping study shows considerable possibilities for improving the planning procedure that was being followed by NREB. A number of states in Northern India are presently capacity deficient which, at least in part, could be attributed to the deficiencies in the planning process. A wrong maintenance decision for a 1000 MW power station alone, for example, can contribute to severe power shortages. While the model presented in this paper leaves some scope for further improvement, the case study results acted as an eye opener to the NREB planners. It also marked a useful first step towards OR application in a prime organization in an important area. Besides replacing the tedious manual process, the model allows the NREB operations planning team to develop better plans that make better use of their resources, enumerate the cost impacts of alternative policies, and above all, foster much awaited cost discipline in the Indian power sector.

While the significant advantages of the new planning model were noted as welcome contributions, it also meant considerable changes in the existing overall planning framework *within* NREB, and also in the manner NREB were to interact with the plant managers of the constituent SEBs as well as other peripheral organizations. The key peripheral organizations relevant for the operations planning included the Indian Railways, the Coal Linkage Committee and Coal India Ltd. There was an element of inertia within NREB itself to shift towards to a new planning paradigm because (a) the new planning model was substantially more complex, and (b) it required much better coordination among the diverse planning subgroups looking after generation, maintenance, fuel supply, transmission, and finance portfolios. The internal changes in terms of reallocating the planning responsibilities and streamlining the coordination among the groups were gradually overcome once the philosophy of the optimization model, and the significant benefits that it entailed, became clearer to the senior engineers. However, the interaction with the external organizations was not as easily managed. The outcome of the optimization model provided less flexibility as compared to the existing procedure. The latter had not been distinguishing among various maintenance schedules in terms of cost performance indices, and hence switching from one plan to another could be accommodated as long as the energy and demand constraints could be satisfied. This sometimes led to difficulty in negotiating the maintenance plans for some stations with the plant managers as well as SEBs having a larger deficit in a month as compared to other SEBs. The optimization results also often suggested dramatic changes in the existing coal allocation. Although this in fact was indicative of the substantial degree of sub-optimality in the existing schedule, the Coal Linkage Committee, without having much experience with such allocation, had numerous difficulties in negotiating with the coal companies and transportation agencies. Both these difficulties of flexibility and a significant departure from coal allocation were compounded by the fact that fixing the problem for a generator, or a link had impacts on a number of other generators/links. Thus, one problem could cascade into another. The lack of complete understanding of how the model works in the absence of appropriate background of NREB planning personnel in optimization theory also contributed in part towards inefficient/delayed resolution of these problems. All these factors slowed down the process of adopting the model as a part of the formal planning process. Additional capabilities were added to the software in due course to draw the maintenance plan according to the existing criteria and compare the cost performance of various maintenance plans. This as well as prolonged exposure to the optimization model, however, helped build sufficient confidence within NREB to resolve these problems.

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