Power Generator Maintenance Scheduler

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Abstract: This paper presents a PC-based Windows application software package for production of optimised maintenance schedules, performing economic dispatch, predicting actual dates for long-term maintenance scheduling and querying the current status of a generating unit from data files. A new heuristic algorithm based on the tabu search has been proposed as a solution. A software package, Automated Optimised Generator Outage Scheduler, was developed using the Power Generation Company of Trinidad and Tobago as the testing ground. The software was implemented in MATLAB 6.5 providing user-friendly Graphical User Interfaces. Numerical results have been obtained and the effectiveness of this developed software has been demonstrated. Selected outputs of the software are presented in this paper for illustration purposes.

Keywords: Preventive maintenance scheduling, heuristic algorithm

Introduction

Power generating companies must generate sufficient electrical power to cater for the varying demands of consumers. Electricity cannot be easily and cheaply stored, so it must be continuously generated based on the customers' demand. The generating company has a declared capacity at any given instant and must supply this contracted demand from its

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resources. These resources include the generating units, transformers and transmission lines. There are many types of generating units that collectively constitute the power system. The generating unit is an electro-mechanical device. An attribute of such equipment is periodic maintenance due to deterioration as a result of prolonged usage. This maintenance is necessary in order to extend the life and improve the overall availability of the equipment. Hence the manner of scheduling this maintenance is of utmost importance from economic and engineering perspectives. Therefore, the optimum schedule is one, which satisfies the many constraints yet maximises service reliability and minimises production cost.

The production of this optimal schedule has been a topic of study by power engineers over the last three decades. These engineers are also faced with the challenge of economic dispatch, that is, operating the power system to supply all demands at minimum production costs, whilst satisfying several constraints. The objective of this research is to develop an automated optimised generator maintenance outage scheduler.

Salient Features of AOGOS

This paper describes the development and functionality of a user-friendly software package developed for power generating companies. The name given to this application is Automated Optimised Generator Outage Scheduler (AOGOS). The specifications of this package are that it must include an interactive Graphical User Interface (GUI) that outputs an optimised maintenance outage schedule, power outputs of online generating units from economic dispatch and a searching method for querying the current status of a particular generating unit within a data file. The developed system has been applied to the

Power Generation Company of Trinidad and Tobago (Powergen). Analysis of the current method used by the above mentioned generating company for scheduling maintenance and economic dispatch will be compared to the outputs of the AOGOS software. The ultimate goal is to improve the reliability and lower the operating costs.

The problem can be divided into four sub-problems:

a) Optimising of maintenance outage schedule over a one-year horizon;

b) Economic dispatch;

c) Five-year scheduling of a single generating unit; and

d) Excel link.

Optimising of Maintenance Outage Schedule

In this software, there are two major constraints that must be satisfied for outage scheduling. These are time constraint and load limit requirements. Firstly, the time constraint simply introduces the requirement that a given generating unit must undergo maintenance for a predetermined length of time, during a specified interval of the time horizon where either the start-time or end-time of the maintenance governs when the maintenance must be started. Secondly, the load limit requirement represents the system load or contracted figure for which the generating company must be able to generate power to meet at every interval of the horizon, regardless of maintenance on generating units. This requirement figure includes spinning reserve capacity. Maintenance on generating units means that these units will be partially or totally unable to contribute to meet this limit. Hence, the resultant schedule must optimally satisfy both constraints if possible.

Economic Dispatch

In this software, there are two major constraints that must be satisfied for the economic dispatching of generating units. The first constraint is load limit requirement as explained in the previous sub-section. The second is the heat rate limit requirement that is a measure of efficiency of the power system and is the contracted figure for which the generating company must strive not to exceed or a penalty is incurred. Hence, the result must be the effective order of loading the generating units at specific outputs. This leads to not exceeding the heat rate limit requirement yet meeting the load limit requirement.

Scheduling of a Single Generating Unit

All generating units of a power system require maintenance on a periodic basis. This software package must provide a forecast of the maintenance schedule over a five-year horizon for a single generating unit, predicting actual dates for the maintenance activities for the generating unit in question.

Excel Link

In power systems, there are records of the current status of each generating unit. These records are necessary to keep track of the duration over which the unit in question was available or unavailable. These records are usually stored in a predefined spreadsheet format. This software must be able to query these records and produce suitable search results. Powergen’s records are stored in Excel Spreadsheet files. This sub-problem has been termed, “Excel Link”.

Outage Scheduling

Variables of Model Formulation

Here are the variables used in the model formulation:

I = Number of generating units

J = Number of planning horizon (weeks [Max = 52]).

$Limit_j$ = Demand/Load at period j. (Assume $Limit_j$ constant for all j)

P_i = Rated output of generating unit i.

R_j = Reserve capacity of I generating units at period j.

M_i = Maintenance duration of generating unit i.

X_{ij} = State Variable if generating unit I is in maintenance at period j, then

X_{ij} = 1; otherwise X_{ij} = 0.

DS_i = Derated state of generating unit i during M_i. $0 < DS_i \leq 1$

P_{ij} = Output of generating unit i at period j. This output is a function of the state variable and the derated state of the generating unit over the planning horizon.

ST_i = Earliest absolute start-time for maintenance duration M_i on unit i.

ET_i = Absolute end-time at which maintenance duration M_i on unit i must conclude.

PS_i = Possible number of schedules for generating unit i during M_i. PS_i is determined by the number of times M_i can uniquely fit during the maintenance window $ST_i \leq j \leq ET_i$.

A generating unit i can undergo maintenance such that it is totally (100%) unavailable and therefore the DS_i = 1. A generating unit i cannot have DS_i = 0, this means that it is totally available and this does not represent behaviour under preventive maintenance. Hence $0 < DS_i \leq 1$ represents either no output or partial output for generating unit i during M_i. Each unit $1 \leq i \leq I$, must be maintained for M_i.

Constraints

Several constraints are identified as follows:

1) Once maintenance of unit i has begun the maintenance must continue for M_i without interruption.
2) The absolute end-time for a scheduled maintenance must not be earlier than its absolute start-time.
3) Maintenance duration M_i on unit I must fit within the maintenance window which is the time between the ST_i and ET_i inclusive.
4) The sum of the outputs of the I generating units over the horizon must meet the load demand for the generated schedule to be valid.

Objective Functions

The objective function can be either one of the following:

1) Minimise the reserve capacity R_j over the planning horizon, or
2) Maximise the reserve capacity R_j over the planning horizon

Fitness Function

The schedule that satisfies the appropriate objective function and the constraints must then be evaluated with the fitness function. This fitness function determines an index for each schedule generated. The magnitude of this index provides a simple relationship with the optimal solution found. An index with the largest magnitude correlates to the schedule for maximising the reserve capacity. Similarly, an index of the smallest magnitude correlates to the schedule for minimising the reserve capacity.

Scheduling Methodology Employed

The method employed was a Redefined Tabu Search because of the simplicity in understanding and implementing the Tabu Search. The following are the general steps used for this method:

1) For the I generating units calculate, PS_i and store in tabu list.

   $\prod_{i}^{I} PS_i$ = max iterations.

2) Determine stopping criteria, number of iterations to perform, where, 1 ≤ number of iterations ≤ max iterations.
3) Generate a random trial schedule: using the tabu list random integers generated to change the ST_i for the I generating units
4) Validate trial schedule against constraints; if schedule valid, evaluate objective function and appropriate fitness function.
5) Store as optimal solution if fitness function regards the trial schedule as optimal.

6) Instead of changing the ST_i for one generating unit as in a normal tabu search go to step 3 and repeat for the number of iterations.

Optimal solution(s) from the number of iterations defined are available. However in actual implementation of the Redefined Tabu Search, the optimisation of the code involved some principles of the Integer Programming Method. Hence, the Redefined Tabu Search has undergone genetic mutation. For large systems, the random technique employed (in Redefined Tabu Search) to move within areas of the entire search space can result in the optimal solution(s) being found, if it exists in a smaller computational run time. The negative aspect of this method is that the same optimal solution, for a given problem, can be encountered more than once. This is due to the random generation of schedules. However the probability of this occurrence has an inverse relationship with the number of iterations set by the user and the number generating units under analysis. The maximum number of iterations the user can set is determined by $\prod_{i}^{I} PS_i$. This is directly related to the maintenance windows of these generating units under analysis. The greater the number of iterations the method is allowed to perform the higher the probability of finding better quality solutions.

Economic Dispatch

Constraints Affecting Economic Dispatch

There are many constraints within the economic dispatch problem. These include:

1) Minimum and maximum power output of each generating unit;

2) Heat rate limit;
3) Load limit requirement; and
4) Availability of generating units.

Factors Affecting Cost

There are many factors, which affect the final cost of generating power from a generating unit, they include:

1) Fuel costs
2) Incremental operational and maintenance Costs
3) Fixed costs of operation
4) Efficiency of generating unit

In order to take into consideration losses in transmission lines between generating units belonging to different power plants, the system cost function becomes an augmented cost function, Eq(1), called the Lagrangian.

$$Cost(\$) = \sum_n \left[F_n(P_n) \times COSINC_n + (O\,\&\,M_n) \times P_n\right] + \lambda \times LOAD - \sum_n \left[P_n + P_{loss}\right] \qquad \text{Eq(1)}$$

Where,

LOAD	= Total power received by the loads
P_{loss}	= Transmission losses
P_n	= Power delivered by generating unit n (MW)
$F_n(P_n)$	= Required fuel input (KJ/hour) into unit n for an output P_n (MW)
$COSINC_n$	= Incremental cost of fuel for unit n ($/KJ)
$O\,\&\,M_n$	= Incremental operation and maintenance cost for unit n ($/MWh)

λ = Lagrange multiplier

The Lagrangian equation, Eq(1), represents an unconstrained problem in which it is required to minimise the Cost function with respect to λ and the generator outputs. Therefore for minimum cost the derivative of Eq(1) with respect to each P_n should be equal to zero, giving the dispatch condition Eq(2).

$$0 = \frac{dF_n(P_n)}{dP_n} \times COSINC_n + (O\&M_n) + \lambda\left[\frac{dP_{loss}}{dP_n} - 1\right]. \qquad \text{Eq(2)}$$

In power generation planning, an approximation is usually made to reduce computer simulation costs. This approximation consists of representing the incremental transmission loss term $\frac{1}{1-\frac{dP_{loss}}{dP_n}}$ as a constant penalty factor, L_n, where L_n may be in the range of $1.0 \leq L_n \leq 1.10$. Further approximation for simulation exercises, results in Eq(3) being approximated where $L_n = 1$ and $O\&M_n$ is neglected to produce:

$$\left[\frac{dF_n(P_n)}{dP_n} \times COSINC_n\right] = \lambda = Min\langle Cost(\$)\rangle \qquad \text{Eq(3)}$$

Software Design and Implementation

The software model, which has been applied to the creation of this software package, was the Waterfall Model with Prototyping. The options provided to the user were implemented as modules. Detailed help screens were designed for all input and output screens.

Software Testing

In order to verify the accuracy of this software, results were subjected to analysis with the Institute of Electrical and Electronics Engineers Reliability Test System (IEEE RTS). This test system comprises thirty-two generators. The IEEE RTS has benchmarked system reliability indices, being the Loss Of Load Expectation (LOLE) and Loss Of Energy Expectation (LOEE) indices for the above specified test system. The LOLE index represents the number of hours per year that the system load shall exceed the available generating capacity while the LOEE index represents the severity of this deficiency in power (usually MW) per year. This test system performs analysis for maintenance scheduling of the 32 generating units. Hence this software can be applied to this test system via a generated schedule. This result (schedule) must then be used to compute the relevant reliability indices. This computation can be done manually or by using reliability software packages which have been previously calibrated according to the IEEE RTS or equivalent. The latter method was selected, using Monte Carlo Simulation.

This test involved generating a schedule for the IEEE RTS system where the weekly load demand values were used to heuristically formulate the maintenance windows for the 32 generating units. The schedule produced was used to compute the respective LOLE and LOEE indices using the Monte Carlo Simulation method. The results are illustrated in Table 1.

(Insert Table 1 about here)

Table 1. Comparison of IEEE results

Case Study of Powergen

Maintenance Scheduling

Powergen has a contractual obligation to the Trinidad and Tobago Electricity Commission (T&TEC) to supply 719 MW capacity and 100 MW spinning reserve. This study includes analysis of the current methods of scheduling and economic dispatch performed by Powergen and comparison of the results produced using AOGOS. The Excel Link was successfully applied to Powergen since the format of the Spreadsheet for proper functioning of that module was adhered to. Powergen's 2000 Maintenance Schedule was used as a test case, where the horizon under analysis was the entire year (i.e. 52 weeks).

(Insert Table 2 about here)

Table 2. Comparison of case study results for maintenance scheduling

Economic Dispatch

A 24-hour hourly analysis was performed using Powergen's generating data on 31st January 2003. The results obtained provided an hourly analysis of how Powergen's generating units should be loaded, given their respective availabilities and declared capacities for successful economic dispatch. Table 3 illustrates cumulatively the hourly results.

(Insert Table 3 about here)

Table 3. Comparison of net heat rate and cost figures for a 24-hour period

Further Study and Upgrades of AOGOS

The following are proposals to increase the functionality of AOGOS:

1) Scheduling can integrate the use of weekly load values to produce a more flexible maintenance schedule. This schedule can then be evaluated by a fitness function which produces LOLE and LOEE indices.
2) The Redefined Tabu Search Algorithm can be modified so that visited areas of the search space are not revisited, thus increasing the probability of finding unique solutions faster.
3) The economic dispatch can be made to accommodate the constraints of ramping the generating units during startup, shutdown and intermediate stages.
4) Additional constraints for economic dispatch include using tie line constraints for multi-area and interconnected systems and revising the objective function to include environmental considerations. The latter can control and reduce the emission of nitrogen and sulphur oxides by fossil-fuel generating units.
5) The economic dispatch can make practical recommendations for the modeling of combined cycle generation plants.

Conclusions

This paper provided a literature review on outage scheduling, examined the economic dispatching principle based on incremental cost curves and described the development of a MATLAB software package entitled AOGOS. The software successfully performed maintenance scheduling, for a maximum of thirty-two generating units, seeking to either maximise or minimise the spinning reserve capacity whist satisfying the load demand, as well as the maintenance window constraints for each generating unit. A user-friendly GUI was developed. It highlighted the periods during the specified horizon when every generating unit under analysis was online and offline.

Accompanying each produced schedule was an analysis of the total power available and the corresponding spinning reserve for every week. Another function successfully implemented was the economic dispatch (again for a maximum of 32 generating units) over an hourly period and a 12-hour period. The latter period provided the option for every generating unit available to be shutdown and/or started up once during this period. Here, an hourly report is generated which suggests how the available generating units should be loaded to achieve minimal cost and maximum efficiency (minimum heat rate). The paper also highlights these minimal cost and heat rate figures. The 5-year maintenance forecast for each generating unit and the process of querying the outage records (in excel spreadsheets) to determine a generating unit's status, were both successfully implemented.

The developed software was applied to a practical power system, the Power Generation Company of Trinidad and Tobago. All the functionalities of AOGOS were successfully applied. Currently at this company, no software package is available to assist in the maintenance scheduling and economic dispatch operations. An analysis by AOGOS of Powergen's maintenance schedule for the year 2000 illustrated that its schedule could have been optimised to produce increased minimum and maximum total power online. The analysis also revealed that an online capacity greater than the desired 920 MW could have been achieved. The results of the economic dispatch for a given 24-

hour period, revealed that the net heat rate and production cost figures achieved by Powergen can be reduced by 8.32% and 10.05%, respectively.

Hence, in order to achieve this reduction in production cost and heat rate, the current strategy used at Powergen to load the generating units must be revisited. In conclusion, since maintenance scheduling determines the availability of generating units for economic dispatch, the AOGOS can result in an improvement in system reliability and economic operation when applied to practical power systems.

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Table 1. Comparison of IEEE results

	IEEE RTS Schedule	AOGOS Schedule
LOLE Hr/Yr	22.00	25.58
LOEE MWHr/Yr	2600	3175

Table 2. Comparison of case study results for maintenance scheduling

	Schedule #1	Schedule #2	Powergen Schedule
Min Cap	948 MW	948 MW	931.5 MW
Max Cap	1118 MW	1118 MW	1098 MW

Table 3. Comparison of net heat rate and cost figures for a 24-hour period

NET	Powergen	AOGOS	% Diff
Heat Rate kJ/kWhr	14 375.74	13 271.7	8.32
Cost $/hr	$888,704	$807,549.3	10.05