# AN OPTIMIZED GENERATOR MAINTENANCE POLICY USING STOCHASTIC SIMULATION

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SUMMARY

Stochastic simulation has been used to develop a technique to minimise the generating system risk whilst accounting for generating cost. This has been applied to the Trinidad and Tobago Electricity Commission power system. A computer program based on a suitable algorithm was developed in order to predict the optimum maintenance schedule.

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## 1. INTRODUCTION

For any system in continuous demand, there is ideally a long period of service ("uptime") interspersed with shorter periods of maintenance ("downtime"). At any given time, the system has a particular hazard rate or proneness to failure. A typical hazard rate function is the "bath tub" curve detailed in Figure 1. Three phases are evident:-

(i) A decreasing initial failure rate normally termed "burn-in" or "infant mortality".

(ii) A period of constant failure rate, "the useful life".

and (iii) A final phase of increasing failure rate, "wear-out".

During the normal working life of the component, the failure rate is constant, $\lambda$ and its value may be estimated from:

$$\lambda = \frac{n}{T} \qquad 1.1$$

where $n$ = number of failures
$T$ = time of failure

The failure of any piece of equipment, including electrical power generating sets, has some element of chance and is therefore controlled by the laws of probability. This process is then referred to as stochastic.

If we consider a power generating system, a state diagram may be constructed, which simply consists of two states up and down with rates of failure and repair of $\lambda$ and $\mu$ respectively as shown in Figure 2. If at time, $t = 0$, we say the unit is in the "up" state or available, then the probability of finding the same unit in either of two states at time t is given by the following equations:-

$$A = \frac{\mu}{\lambda + \mu} + \frac{\lambda e^{-(\lambda + \mu)t}}{\lambda + \mu} \qquad 1.2$$

$$U = \frac{\mu}{\lambda + \mu} - \frac{\lambda^{-(\lambda + \mu)t}}{\lambda + \mu} \qquad 1.3$$

where A is the availability and U the unavailability.

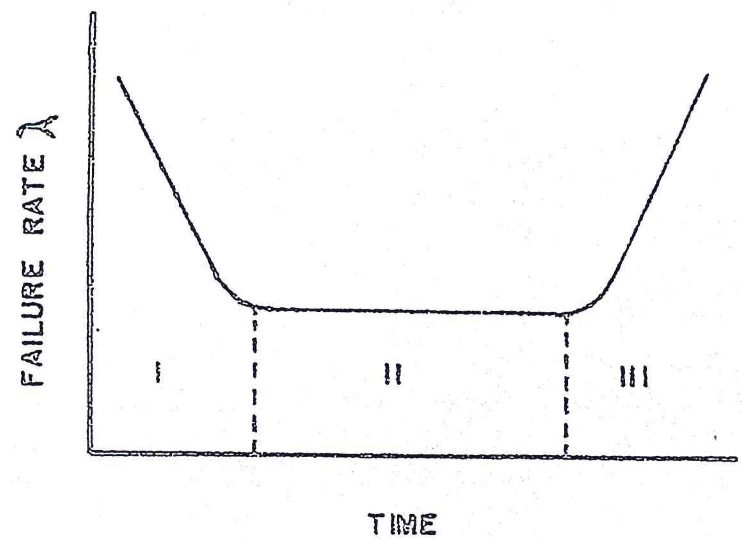



FIG. 1 FAILURE RATE CURVE.

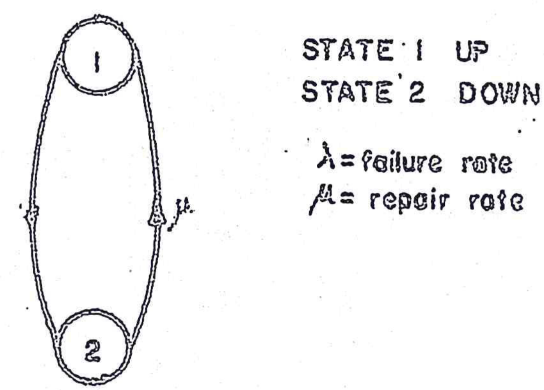



FIG. 2 MARKOV CHAIN MODEL.

When t is large the equations reduce to:-

$$A = \frac{\mu}{\lambda + \mu} \qquad \text{and} \qquad U = \frac{\lambda}{\lambda + \mu} \qquad 1.4$$

and as $t \to \infty$, the system state becomes independent of the initial state. We may extend our description of the process by defining a mean "up time", M, or "Mean time of failure" (MTTF), and a "mean down time", $\nu$, or "mean time to repair" (MTTR). The determination of values of M and $\nu$ in any operating system is derived from performance data.

For a unit in constant demand, a generating system model may be developed using values of A and U derived from values of $\lambda$ and $\mu$. This model would then consist of discrete capacity states and the probability of being in each state. The probability of being in a particular state is the product of the availability and unavailability of the units dependent upon their condition in the state. For example, a capacity state of two units at full capacity, would have a probability of $A_1 \times A_2$ and if unit 2 were unavailable then the probability would become $A_1 \times U_2$. This leads to defining a cumulative probability state table, where the cumulative probability of being at full capacity is unity.

Naturally for a system of only two units, the result is trivial with only four possible capacity states, however the problem of maintaining the probability of supply above a pre-determined critical level becomes complex for electrical power generating systems having twelve or more units. In this paper, a technique of stochastic simulation is presented which enables scheduled maintenance to be performed on all units in turn whilst maximising the probability of meeting demand in relation to the fluctuating load demands over the period of study.

## 2. MAINTENANCE SCHEDULING OF GENERATING FACILITIES

Annual or periodic maintenance affects generating systems in two ways:-

(i) It increases the cost of generation by the commitment of sets with higher incremental costs

and (ii) Increase the risk of generator shortages.

Many techniques have been devised to schedule the maintenance of generating facilities. These techniques normally concentrate on determining planned outages for maintenance scheduling by optimising some function of the operating system over the maintenance period.

Hara, Kimura and Honda[1] based their system optimisation on a cost function which considered not only the operating costs of the generator units but also the system reliability. Economic operation is determined by value of the cost function which gives the optimum number of operating units and the units designated for overhaul in a given time period.

Christiaanse and Palmer[2] related the problem to three guidelines:-

(i) The selection of an independent or decision variable.

(ii) The selection of an objective function as a function of (i).

(iii) The limit of the constraints on (i).

necessitating the availability of the following data:-

(i) The weekly gross generating reserve per annum.

(ii) The number of scheduled outages for the year.

(iii) The loss of reserve value and the duration of each outage.

The constraints considered most appropriate were:-

(i) Crew and manpower availability.

(ii) Control of the time between outages.

(iii) Seasonal limitations.

(iv) Effect of pre-scheduled maintenance.

The problem is then formulated to maximise the net reserve and levelise the net reserve over the maintenance period. Garver[3] attacked the same problem but devised a loss of load probability utilising the concept of effective load carrying capacity of generating units.

These heuristic approaches, therefore, considered each generator unit separately to select the optimum outage interval using an objective criteria based on net reserve, risk or minimum total production costs.

Quintana and Zurn[4] recognised that individual generator performances could not be taken in isolation but were subject to coupling constraint. This reduced the problem to one of smaller proportions and the application of ordinary dynamic programming to conveniently chosen groups of generating units. The strength in this technique lies in the grouping criterion in which all units within a group must have the same performance specifications and thereby overlapping maintenance outages for the members of the group are not permitted.

Khalib[5] critically reviewed the various techniques utilized for maintenance scheduling and extended the analysis by describing a system based on stochastic simulation which would provide more reliable operation for the system and better assessment of risk and system costs. The means of scheduling in this paper further extends this study and formulates a computer program to rapidly analyse the system and produce an optimum maintenance schedule.

## 3. MAINTENANCE PROGRAMMING THROUGH STOCHASTIC SIMULATION

The most important criterion in electrical power generation is the reliability of the system. This is normally expressed as the duration of loss of supply to the average consumer in hours per annum. In order to determine this value during any given period, the energy curtailment (EC) must be determined and this is divided by the peak demand during the period. By then summing all the periods in the year, an interruption duration index IDI may be determined and this reflects the risk of supply not meeting demand.

It is desirable to compare the risk between different periods as these will include different units undergoing scheduled maintenance. In this context, the probable average hours of interruption per day may be calculated from:

$$\text{IDI} = \frac{\text{Probable EC}}{\text{Peak x N}} \quad \text{Hrs/day}$$

where P is the peak demand of the period
N is the number of days in the period

This may be obtained by combining the generation model obtained by stochastic simulation with some load model representing the demands on the system over the time period.

Having defined the load and generation models, the process of combination involves dividing the load duration into N steps corresponding to the generation capacity states with some pre-determined set commitment schedule. The amount of energy contributed by the sets is derived from the equation:-

$$E = \tfrac{1}{2}(h_n + h_n \quad . \quad x \quad (L_{n+1} - L_n) \times (1 - A_g)$$

where $L_{n+1} - L_n$ is the load between two adjacent steps

$h_n$ and $h_n$ is the corresponding duration

and $A_g$ is the cumulative probability of being at a certain capacity state g corresponding to the load at step n+1 or below

E is calculated for all the steps in the load duration curve to give the actual total energy supplied, $E_s$.

$E_s = \sum_{n=1}^{N} E$ where N is the number of intervals.

The amount of energy required is the area under the load-duration curve, $E_R$. The difference between the energy supplied and that required gives the energy curtailment, $E_c$ the amount by which supply fails to meet demand.

$$E_c = E_R - E_S$$

For each value of $E_c$ a corresponding value of IDI may be formed.

The next step is to obtain the effective size of each generator set in the system. This effective size, E gives an indication of the importance of each individual set with respect to maintaining system reliability. This effective size is defined as:-

E = set size (MW) x set long-term availability

Having calculated the values of E for each set, they should then be applied to the periods so that the highest value of E coincides with the least value of IDI.

As soon as a set is withdrawn for maintenance in a particular period, the removal requires the new value of IDI to be calculated. Removal may be effected by a method involving less computation of capacity states. The method used the following equation:-

$$P_2(x) = \frac{P_1(x) - P_2(x - c) \times \upsilon}{A}$$

where $c$ is the size of the unit removed, MW

$x$ is the outage capacity in the capacity state table

$P_1(x)$ is the original cumulative availability of an outage capacity

$P_2(x)$ is the new cumulative availability after the removal of c

$P_2(x - c)$ is obtained from the table being formed and is equal to 1 for $x \leq c$

$\nu$ is the unit unavailability

A is the unit availability

The new capacity state table so developed replaces the original and becomes the generation model for the period which is used to calculate the new value of IDI. The process continues by designating the set with the next largest effective size to the period of next lowest IDI. The overall exercise is repeated until all the sets are allocated a certain period. This results in a listing of the generator sets in which the removal of each set for maintenance in a given period would minimise the risk of generating capacity shortage.

This method is ideally suited to digital computation and an algorithm for the process is given in Figure 3.

## 4. SYSTEM MODEL

From the algorithm detailed in Figure 3, a computer program was written. This was designed to simulate the maintenance schedule of the Trinidad and Tobago Electricity Commission. A schematic diagram of the system under consideration is shown in Figure 4. This indicates three main power stations at Port-of-Spain, Penal and Pt. Lisas. All three are strategically located to cater for their respective load centres and are interconnected by external sub-stations and tie lines. There are two minor stations, at Savonetta and on Tobago, but these are smaller scale units which would not significantly affect the study.

Table 1 details the generating capability of each of the three main stations including unit numbers designated for the study. One unit at Penal of 5 MW capacity is not included because of its size and determined obsolescence. The unit commitment order is defined

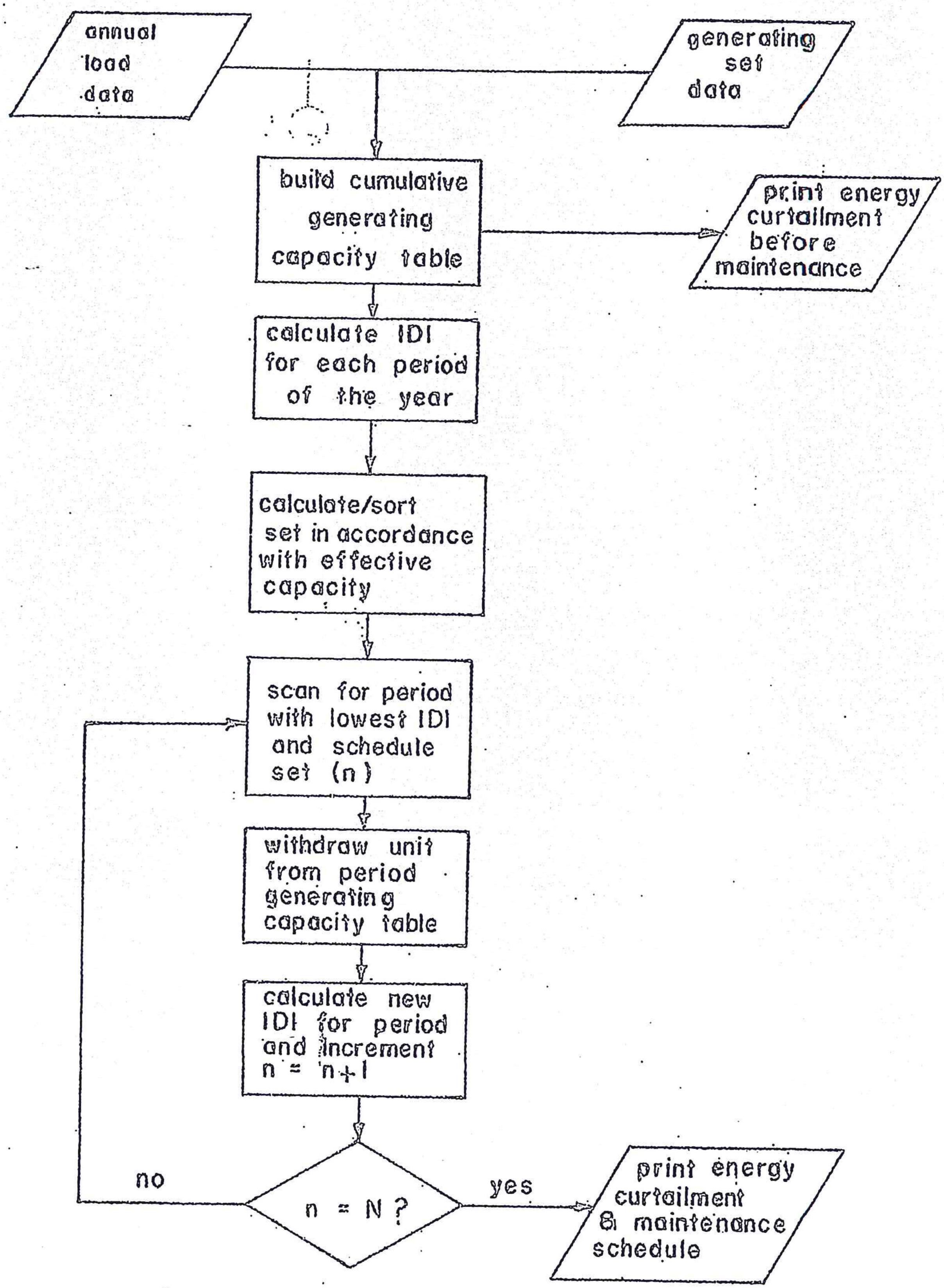



FIG. 3 MAINTENANCE SCHEDULING ALGORITHM.

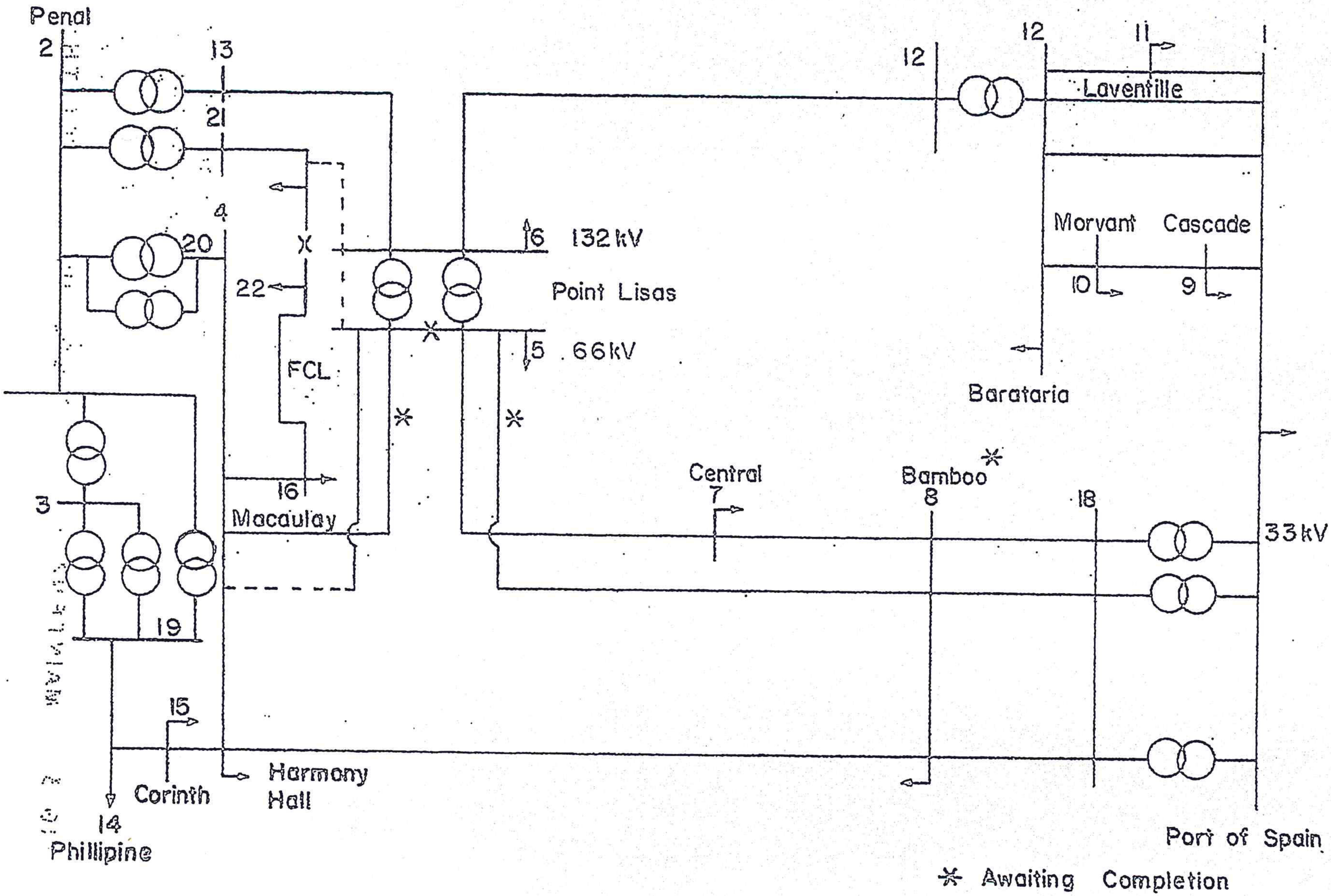



FIG. 4 TRINIDAD AND TOBAGO POWER-SYSTEM LAYOUT.

TABLE 1

GENERATING CAPABILITY OF THE THREE MAIN STATIONS

| LOCATION | UNIT. NO. | MW RATING | AVAILABILITY | COMMITMENT ORDER | UNIT. NO. IN STUDY |
|---|---|---|---|---|---|
| Port-of-Spain | 1 | 50 | 0.774 | 5 | 1 |
| | 2 | 50 | 0.827 | 4 | 2 |
| | 3 | 80 | 0.724 | 2 | 3 |
| | 4 | 80 | 0.850 | 1 | 4 |
| Penal | 3 | 20 | 0.808 | 11 | 5 |
| | 4 | 20 | 0.730 | 12 | 6 |
| | 5 | 20 | 0.865 | 10 | 7 |
| | 6 | 20 | 0.911 | 8 | 8 |
| | 7 | 20 | 0.897 | 9 | 9 |
| Point Lisas | 1 | 88.1 | 0.980 | 3 | 10 |
| | 2 | 20 | 0.980 | 6 | 11 |
| | 3 | 20 | 0.980 | 7 | 12 |

as the relative economic importance of each unit, this includes fuel costs which make units 3 and 4 the most expensive even though they are of a lower rating than unit 10. This is because the former are steam generators whereas the latter is gas fired.

This table gives sufficient information to build the generation model, once the load duration curve for all the periods of the study has been determined. The period chosen as the base for the study was one month as this is the expected average duration of maintenance on one of the units. The calculation of the load curve was then undertaken with expected monthly peaks and projections being defined (Table 2).

TABLE 2

MONTHLY PEAK LOADS

| MONTH | 1977 PEAK LOAD (MW) | FORECASTED 1978 PEAK LOAD (MW) |
|---|---|---|
| Jan. | 193.3 | 212.6 |
| Feb. | 201.2 | 221.3 |
| March | 207.6 | 228.4 |
| April | 203.1 | 223.4 |
| May | 210.0 | 231.0 |
| June | 210.5 | 231.6 |
| July | 206.9 | 227.6 |
| August | 209.4 | 230.5 |
| Sept. | 215.6 | 237.2 |
| Oct. | 221.4 | 243.9 |
| Nov. | 229.8 | 252.8 |
| Dec. | 222.4 | 245.0 |

The calculation of the load curve is simplified for the Trinidad and Tobago system as no appreciable seasonal changes in demand occur. There is, however, some peaking of the load in the month of November with a decrease until minimum demand for the year is experienced in April. The shape of the demand curve was assumed consistent from month to month, the only variations being the peak and base loads. On this basis, the method adopted was to develop the load duration curves using the annual load duration curve as a reference on monthly demand. The resultant loss in accuracy was deemed worthwhile when considering the saving on computation and computer storage. A simulation of the power generating system in 1980 was thus performed with projected monthly peak loads as shown in Table 2.

## 5. RESULTS

The computer program was written in Fortran IV for use on the University of the West Indies ICL 1902A computer. The program was maintained on discfile so only a limited number of data cards need be input. These cards contain the information detailed in Table 1. The program is designed to accept no more than two units for maintenance in each monthly period. This is a constraint that would satisfy any medium sized power system since scheduling more than two units for maintenance would substantially increase the generation risk. Only when the number of units in the system exceeds twenty-four does the program allow additional units to be scheduled.

The program tabulates all output. Firstly a generator unit effective size table is printed which list the actual and effective size of all the generator units. The effective size of the Trinidad and Tobago system is 416.56 MW compared to an actual size of 488.1 MW. This represents an overall system availability of 0.854. For each simulation, the generation model is developed giving the system capacity state table with each unit removed in turn. For the desired maintenance schedule some capacity state curves are included in Figure 5, these detail the cumulative probability of not maintaining output above each capacity state level. Curve 1, for example, indicates that for a load demand of 488.1 MW (the actual system capacity) there is a cumulative probability of 1.0 that the demand will not be met. However, for the same system, there is only a probability of 0.036 that a demand of 300 MW will not be met.

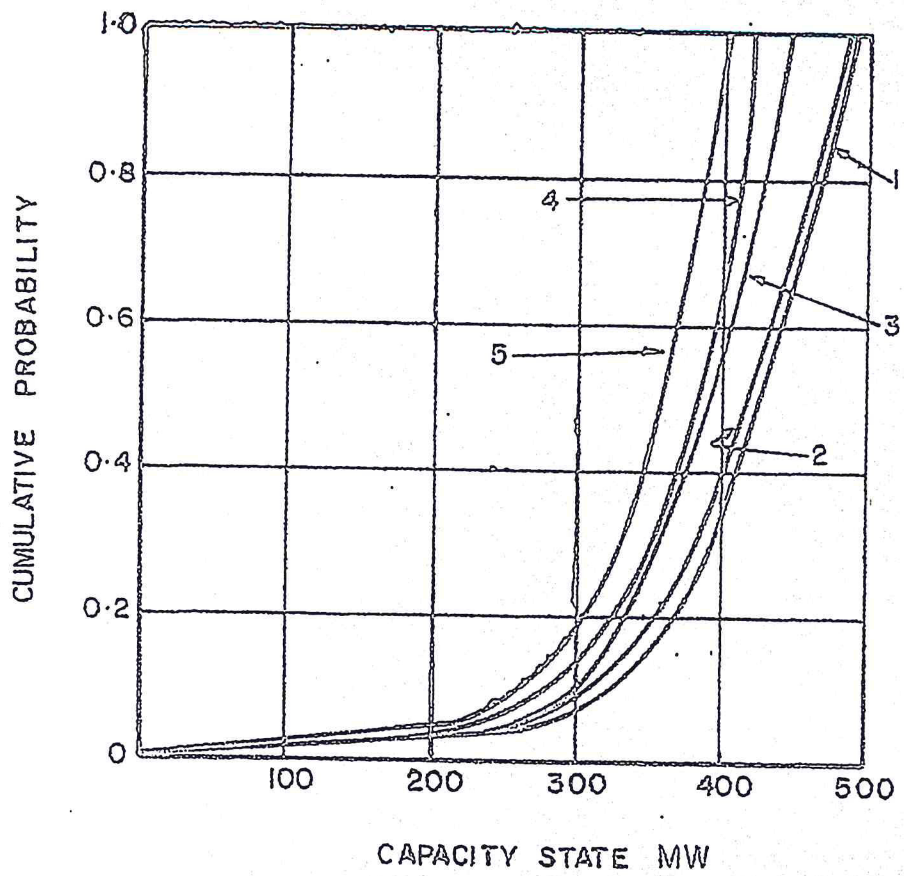
Table 3 gives the table of results representing the ultimate aim of the program. This details for each period:-

(i) the generator unit to be scheduled for maintenance

(ii) the IDI for the system before scheduling the units

and (iii) the IDI for the system after removal of the generator unit for each period.

This indicates an optimum maintenance schedule which minimises the risk of inability to meet demand whilst committing those units with highest running costs to be maintained in those periods where there is a minimum curtailment probability.




| Curve | Unit Out |
|---|---|
| 1 | None |
| 2 | No. 8 |
| 3 | No. 2 |
| 4 | No. 3 |
| 5 | No. 10 |

FIG.5 CUMULATIVE PROBABILITY OF ATTAINING CAPACITY STATES WITH SPECIFIC UNITS REMOVED.

TABLE 3

PREDICTION OF MAINTENANCE SCHEDULE

| PERIOD | UNIT FOR MAINTENANCE | IDI BEFORE MAINTENANCE | IDI AFTER MAINTENANCE |
|---|---|---|---|
| 1 | 10 | 0.0104 | 0.2357 |
| 2 | 4 | 0.0134 | 0.0775 |
| 3 | 1 | 0.0160 | 0.0485 |
| 4 | 3 | 0.0142 | 0.0512 |
| 5 | 12 | 0.0170 | 0.0418 |
| 6 | 8 | 0.0173 | 0.0392 |
| 7 | 2 | 0.0157 | 0.0544 |
| 8 | 11 | 0.0168 | 0.0413 |
| 9 | 9 | 0.0198 | 0.0423 |
| 10 | 7 | 0.0227 | 0.0489 |
| 11 | 6 | 0.0270 | 0.0490 |
| 12 | 5 | 0.0232 | 0.0467 |

## 6. CONCLUSIONS

A technique using stochastic simulation has been applied which may be used to minimise the generating system risk whilst accounting for generating costs. A computer program using a suitable algorithm is able to predict the optimum maintenance schedule for the Trinidad and Tobago Electricity Commission power system. This simulation system may be extended to update the maintenance schedule by deviations from plan due to forced outages,prolonged outage or unpredictable labour and parts shortages. Thus modifications in the generating procedure may be incorporated to obtain new risk and cost estimates of the maintenance programme as operational experience dictates.

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