PEAK SHAVING CONSIDERING STREAMFLOW UNCERTAINTIES

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Abstract
The main thrust of this paper is peak shaving with a Stochastic hydro model. In peak sharing, the amount of hydro energy scheduled may be a minimum but it serves to replace less efficient thermal units. The sample system is die Kainji hydro plant and the thermal units of the National Electric Power Authority. The random nature of the system load is re-organized by using a Markov load model. The results include a modification of the expected load to be served by the array of thermal units, and the optimum schedule for the economic operation of the plant as a peaking load.

1. Introduction

Fuel cost at a conventional hydro plant is nil. On the other hand, the production cost at a thermal plant can be formidable. The co-ordination of these sub-system is an economic problem. A small flaw in the co-ordination can have a significant impact on any nations economy. This calls for proper identification and modelling of the major variables.

Optimal operation of hydro-thermal facilities has received a considerable attention among optimisation problems. Sokkappa [1] has suggested a deterministic formulation of the hydro-thermal scheduling problem. Deterministic formulation assumes that the magnitudes of the reservoir inputs are known in advance. This formulation is unrealistic as streamflow cannot be predicted accurately in advance. Stochastic formulation is a method that is currently receiving most attention in literature [2,3]. This modelling incorporates the random nature of reservoir inflow. Reservoir inputs in particular months are specified as expected values.

In this work, a stochastic hydro model is used to peak shave the expected load pattern; this results in a modification of the expected load to be served by the array of thermal units. The stochastic nature of the load is recognised by representing the load with a Markov chain model. The computer simulation yields the optimal hydro discharge schedule for the most economic loading of the hydro plant over a one year planning period.

2. The Need For Peak Shaving

The input-output curve of a thermal unit is generally non-linear. It is often expressed as a quadratic polynomial:

$$C = a + b.Ps + c.Ps^2 [₦/h] \qquad (1)$$

where a, b, c are constants and Ps is the output of the machine in MW. From Equation (1), the production marginal cost of the unit grows as the MW output of the machine is increased (which corresponds to increasing demand). In peak shaving the hydro energy is employed to replace some of the thermal generation during peak loads. In order to obtain the maximum benefit from this replacement, the least efficient thermal generation is replaced first.

Though the hydro energy is often scheduled as peaking load, electric utilities with ample water-power resources may use them for base load operation. Base loading permits the release of maximum hydro energy. On the other hand, the amount of hydro energy scheduled in peak loading may be a minimum but it is effective in relieving the system from depending excessively on less efficient thermal unit.

3. Stochatic Hydro Model

A system with one steam plant in parallel with one steam plant is considered. The objective is to minimize the cost of fuel expended for the thermal generation. A detailed treatment of the dynamic programming theory used in this work is given elsewhere [4]. The recursive equation for dynamic programming solutions is:

$$F[v(k),k] = \min_{u(k) \in U(v(k),k)} \{c[v(k),u(k),k] + F[v(k-1),k-1]\} \quad (2)$$

Where,

$F[v(k),k]$ = minimum cost (₦) for running the system from the initial state to state v(k) at the end of stage k.

$c[v(k),u(k).k]$ = cost for a single stage k

k = stage (or period) number

v(k) = content (or state) (m^3) of the reservoir at the end of period k

u(k) = discharge (m^3) through the hydraulic turbine during period k

U(v(k), k) = admissible domain in the control spare at state v(k) stage k.

Equation(2) is minimized subject to the following constraints

$$P_d(k) = P_s(k) + P_h(k) - P_I(k) \quad (3)$$

$$v(k) = v(k\text{-}l) + r(k)\text{-}u(k)\text{-}s(k)\text{-}l(k) \quad (4)$$

where,

$P_d(k)$ = energy demand in period k

$P_h(k)$ = hydro generation in period k

P1(k) = transmission loss, in period k

r(k) = reservoir input in period k

s(k) = spill at the hydro plant in period k

I(k) = loss due to evaporation and seepage from the reservoir during period k.

Water resource systems are invertible [5], hence the decision variable u(k) can be solved in terms of the state variable v(k). From Equation (4):

u(k) =v(k-l) –v(k) + r(k) e- s(k) - I(k)

or

$u(k) = \phi[v(k\text{-}l), v(k), r(k), s(k), I(k)]$

If the stochastic variable, r(k) is divided into M discrete levels, $r_1, \ldots r_M$ with probabilities $P_1, \ldots, P_M$ respectively then ϕ_m corresponds to the m-th level of the random streamflow. Equation (2) can now be written in its stochastic form as Equation (5)

$$F[v(k),k] = \min_{u(k) \in U(v(k),k)} \{c[v(k),k) \sum_{m=1}^{M} P_m [c[v(k),\emptyset_m k] + F[v(k-1),k-1]\} \quad (5)$$

Security dispatch may limit the ranges of the system variables:

$\underline{v}(k) \le v(k) \le \bar{v}(k)$ (6)

$\underline{u}(k) \le u(k) \le \bar{u}(k)$ (7)

$P_s(k) \le P_s(k) \le \overline{P_s}(k)$ (8)

where,

$\bar{v}$ and $\underline{v}(k)$ = upper and lower bounds on v(k)

$\bar{u}(k)$ and $\underline{u}(k)$ = upper and lower bounds on u(k)

$\bar{p}_s(k)$ and $\underline{P}_s(k)$ = upper and lower bounds on $p_s(k)$.

4. Stochastic Load Model [6]

In this study, a consideration of the expected load is incorporated in the modeling. The stochastic nature of the load is recognized by using a load model based on Markov chain. The modelling assumes that the loads in a particular period can be adequately represented by a set of N load level or states which occur in a random sequence, Figure 1. Each daily peak load L_i lasts for e < 1 day and is always followed by the filed base load L_o

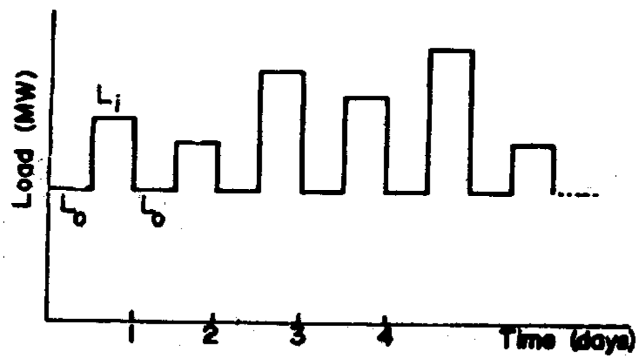

Figure 1: Sequence of loads used for load Model

The expected value of the load demand in period k with D days is

$$P_d(k) = \sum_{i=1}^{N} A_i L_i$$

where,

$A_i = cn_i/D$

n_i = average number of times the system load is in state L_i in period k.

5. Numerical Example

This section illustrates the implementation of the formulation presented in Section 3. A realistic test system, Kainji hydro plant, is used to peak shave the expected energy demand on the national grid in 1988. The simulation uses streamflow data obtained from 7 years of historic record between January 1983 and December 1989 streamflow information is presented in Table 1. In the simulation the reservoir inputs are approximated to the nearest 50m^3/s. The range of possible inflows (the 84 data points on Table 1) are divided into M discrete levels. (Alternatively the range of inflows for each month, for the 7 years, can be considered independently)

Table 1 Streamflow Information (m^3/s)

Month	Year						
	1983	1984	1985	1986	1987	1988	1989
January	810	760	750	740	698	765	758
February	692	642	666	663	670	670	651
March	210	200	162	164	159	160	170
April	237	240	230	230	240	230	220
May	24^4	206	211	201	198	205	200
June	460	400	432	434	440	434	430
July	600	562	596	591	592	600	580
August	1267	1170	1192	110	1128	1200	1220
September	2641	2790	2715	2630	i498	2800	2600
October	2420	21)53	2471	2442	2400	2500	2425
November	1272	1361	1235	1240	1250	1240	1230
December	1520	1492	1470	1500	1550	1500	1460

The characteristics of the hydro plant under study are summarized in Table 2. The minimum discharge is assumed to be 500m^3/s.

The energy generated by the hydro plant in period k, E_H (k), is approximated by Equation (9), (see Reference 7):

$$E_H(k) = u(k).\ [v_o + (1/2)\ (v(k) + v(k-1))].\ \eta \quad (9)$$

v_o is the minimum allowable storage at the plant and v(k) is the usable water storage at the end of period k.

Table 2. Characteristics of the Hydro Plant

Gross storage (m^3 x 10^9)	= 15	
Net storage (m^3 x 10^9)	= 12	
Capacity in MW	Firm output	= 880
	Installed	= 960
Discharge (m^3/s)	average	= 1830

at peak load=3900

The conversion efficiency η, estimation at maximum storage, capacity [MW] and discharge is 4.5584E-15 MWH/{$(m^3)^2$}.

The expected load pattern used in this study is given in Table 3. The thermal portion of the system consists of 51 thermal units located at Egbin, Sapele, Afam, Delta, and Ijora power plants. Each unit is considered to have input-output curve given by Eqn. (1). A single curve is needed to represent the thermal units while scheduling the hydro system. The composite cost function (10):

$$CT = 2061.406 + 2.370699P_{ts} + 7.707244\text{x}10^{-4}P_{ts}^{2} \quad [₦/h] \qquad (10)$$

is obtained by dispatching the thermal units at the same incremental cost, but respecting the power limits for the individual units. For a fuller discussion on this topic to the interacted reader should see Reference [8]. In Equation (10) P_{ts} is the total generation from the thermal units. The data used in deriving Eqn. (10) are summarized in Table 4.

Table 3. Expected Load

Month	Expected Load (MW)	Expected Energy (MWH)
January	1557.250	1158594
February	1549.872	1078711
March	1661.057	1235826
April	1449.570	1043690
May	1421.032	1057248
June	1418.214	1021114
July	1416.526	1053895
August	1441.195	1072249
September	1605.652	1156069
October	1695.222	1261245
November	1751.154	1260831
December	1703.791	1267621

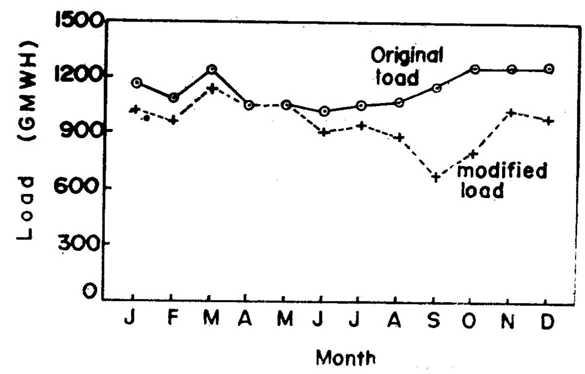

Fig. 2: Effect of peak shaving on expected load.

Table 4. Thermal Unit Characterist

S/No.	Max MW	Min MW	a (₦/h)	B (MWh)	c (₦MW2)h	Type	Plant
1 – 6	220	50	39	4.035	0.00071	Gas	Egbin
7 – 12	116	30	29.5	5.025	0.00097	Steam	Sapple
13 – 16	70	10	26.625	5.635	0.012	Gas	Sapple
17 – 22	70	10	26.625	5.635	0.012	Gas	Afam
23 – 24	36	4	3.9	5.75	0.031	Gas	Delta
25 – 32	25	2	3.9	5.8	0.031	Gas	Afam
33 – 44	20	2	3	5.94	0.04	Gas	Delta
45 – 47	20	2	3	5.94	0.04	Gas	Ijora
48 – 49	17.5	2	3	5.95	.041	Gas	Afam
50 – 51	10	2	2.5	5.99	0.045	Gas	Afam

Fuel cost is taken to be 0.5 Naira/MBtu for each of the units. In the sample study, the management specifies the volume of water in storage to be maximum at the beginning of January and that the volume should be returned to the same level at the end of December The optimal schedule is given in Table 5. From the results the total fuel cost (for one year) is ₦57,129,480 when the hydro energy is used as peaking load. This cost would be ₦66,995,670 in the absence of the hydro energy. A modification of the expected system load after peak shaving is depicted in Figure 2.

6. CONCLUSION

In this paper a peak shaving operation using a stochastic hydro model has been presented. The results are realistic and economical. This model can be adopted by an electric utility for fuel budgeting and planning. With the application of dynamic programming in successive approximations, the model can be adopted for a multiplant hydro system. Streamflow correlation is considered in [9].

Table 5: Schedule for the Hydro Plant

Period	Discharge	Volume at end of period	ED	EH	ET	TC
1	2.027932E + 09	12000	1158594	138661.9	101992	5029266
2	1.646537 E + 09	12000	1078711	112583.6	966127.4	9788016
3	1.400013 E + 09	11040	1235826	92664.68	1143161	1.538555E + 07
4	0	11520	1043690	0	1043690	2.051007 E + 07
5	0	12000	1057248	0	1057248	2.57081 E + 07
6	1.627886 E + 09	11520	1021114	109527.4	911586.6	3.024294 E + 07
7	1.587909 E + 09	11520	1053895	105100.5	948794.6	3.495848 E + 07
8	2.7149474 E + 09	12000	1072249	182667.1	889585.9	3.942087 E + 07
9	6.942856 E + 09	12000	1156069	474724.8	681344.3	4.301728 E + 07
10	6.619474 E + 09	12000	1261245	452613.2	808631.8	4.714536 E + 07
11	3.332572 E + 09	12000	1260831	227867.9	1032963	5.22206 E + 07
12	4.0176 E + 09	12000	1267621	274707.5	992913.6	5.712948 E + 07

Discharge is in cubic metres
Volume is in 1000000 cubic metres
Energy is in MWH
ED = Expected energy, MWH
EH = Hydro generation, MWH
IT = Thermal generation, MWH
TC = Total Cost, *H*

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