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Mathematical Model for Daily Dispatch Scheduling, Power System Economic Analysis and Alternative Generation Planning Based on the Daily Load Profile

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Abstract: This paper proposes a mathematical model to project and analyse the demand and supply patterns of the Sri Lankan power system, in an economic and optimal operation perspective using optimization techniques. The model is implemented on a spreadsheet. It is based on the merit order economic dispatch of power plants, possible hydrological conditions and the daily load profile. The comparative fuel costs of thermal power plants, historical rainfall data and the daily load profile of a representative day is taken as inputs. The future demand and power plant investment projections are made based on the Long Term Generation Expansion Plan of the Ceylon Electricity Board. The use of the daily load profile is a complementary approach to the purpose of this model to support the approach of WASP software which is based on the annual load duration curve. This alternative approach's advantages such as the ability to visualize and analyse daily cycling patterns of each power plant and ability to calculate the system running cost for different hydrological conditions are discussed. The model is also customizable for different planning scenarios. Examples of such custom applications of the model are also presented.

Keywords: Generation planning, Load profile, WASP, Daily load curve, Load distribution curve, Dispatch scheduling

1. Introduction

Even though energy market has been open for private power producers in smaller scale, Sri Lanka's large generation introduction policy is still centrally decided upon by Ceylon Electricity Board (CEB) and the government. Dynamic expansion planning is essential in order to determine the most suitable energy mix for the country's power system.

The cost of operation of a power system is dominated by the fuel cost of the system's power plants. The cost of fuel is reflected in several ways. The most conventional approach is the incremental cost based on the economic dispatch [1]. Several countries use non conventional methods i.e. Availability Based Costing [6]. In Europe, there are more complex costing structures in the due to the development of Europe's Super Grid [4]. The proposed model is considering the incremental cost based dispatch strategy.

WASP is the primary tool used by CEB for long term generation expansion planning. The software has its limitations as described in the following chapters. Since fuel prices, climate and other factors are uncertain, probabilistic approaches have been suggested in [5,6].

The mathematical model and the software tool that is proposed in this paper complement the limitations of WASP and provide a flexible modelling environment for daily dispatch scheduling, power system economic analysis and alternative generation planning based on the daily load profile. The model does not demand additional input data than WASP does but availability of additional data will make the complementing more accurate and more realistic.

It is important to look for new technologies and new energy mixes to compose the country's power system in order to improve security of the country's energy economy. The researchers and policy makers should consider the economic feasibility of such options and then conduct technical feasibility studies and implementation procedures.

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2. WASP Software and its Limitations

2.1 Overview of WASP

Wein Automatic System Planning (WASP) is the FORTRAN based software used by Ceylon Electricity Board (CEB) to generate long term generation expansion plan, every year [10]. WASP is an advanced proprietary software by International Atomic Energy Authority (IAEA) [7]. It uses advance algorithms to arrive at the most economically viable generation expansion plan of the power system up to 30 years in to the future. CEB publishes a Long Term Generation Expansion Plan every year, which has a 15 year planning horizon [10].

WASP requires a large number of inputs in order to get its comprehensive power system expansion schedule. The inputs include data for load forecast and load seasonal variation, hydrological conditions, technical and economic characteristics of power plants, their construction costs and operating costs etc.

2.2 Input Modules of WASP Software [8]

Load Duration Curve (LDC)

WASP takes in data through 3 modules namely LOADSY, FIXSYS and VARSYS. LOADSY is the module that takes in the load data within the window of which the generation expansion plan should be generated. The data is given as load duration curves (LDC) valid for a period of time in a year. Normalized LDC data is given either in a manner of a 5^{th} order polynomial or as discrete points connecting which the desired LDC is generated.

The Figure 1 shows a sample load distribution curve. Figure 2 shows two hypothetical daily load curves drawn on the same figure. Both these daily load curves directly correspond to the LDC given in Figure 1.

The daily cycling patterns of generators in the two daily load curves are entirely different from each other hence their economic effect too is different. WASP cannot visualize the daily cycling pattern of generators in the power system. The proposed model in this paper suggests a solution to this problem.

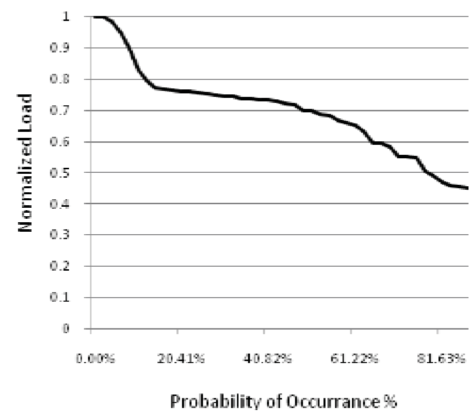

Figure 1 - Sample Load Duration Curve

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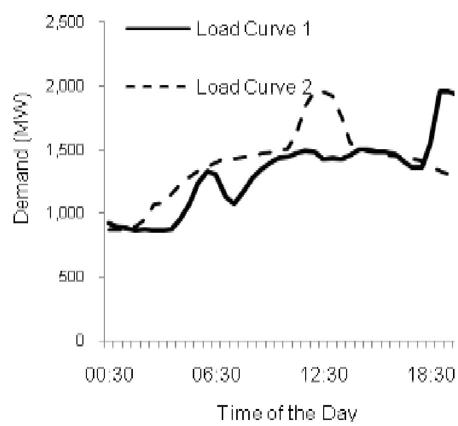

Figure 2 - Daily Load Curves Corresponding to Figure 1

Fixed Power Plants and Candidate Power Plants

FIXSYS and VARSYS modules incorporate data of power plants of the power system to WASP. FIXSYS takes in data of power plants that exist in the power system at the time of running WASP and data of committed power plants which will get added to the system in the future. VARSYS takes in data of "candidate power plants" that should come in the future and that are suggested by the user. Specifications of candidate power plants should be given in detail. The whole candidate power plant floats in time and appears at the optimal time but the size and other specifications do not float in order to achieve the optimal specification. In order to arrive at the optimal specification of a plant, candidate plants with all possible combinations of varied specifications should be input to WASP which can be a tedious task. The model proposed in this paper suggests a rectification to this problem by means of allowing the specifications i.e. size of a plant to float so that the optimal specification is arrived at. Narrowed down possibilities can later be fed in to WASP to get better results using WASP's advanced algorithms.

3. Supplements to WASP Provided by the Proposed Model

i. Accommodating the daily load curve to visualize the effects of daily cycling patterns of power plants as described in 2.2.

ii. Allowing specifications of candidate power plants to float so that the optimal specification is found. The optimal specification then can be input to WASP as a candidate power plant so better generation expansion plan is achieved.

iii. Flattening the daily load curve or improving the load factor is one challenge posed on the utilities. Energy Storage facilities such as pumped storage power plants, electric vehicles i.e. Vehicle to Grid (V2G) concept, can improve the load factor of the daily load profile. The proposed model allows visualizing the effects of energy storage facilities, on the daily load curve.

iv. Economic consideration is important not only at the generation expansion stage but also at the daily dispatch. Daily cycling of thermal power plants should be considered in optimal dispatch, e.g. certain thermal plants should be operated for a minimum number of hours once started, in order to avoid cold starts which cost huge sums of money. WASP is not capable of taking in the minor changes such as hydrological conditions, incremental costs of plants, water release constraints and suggesting the optimal dispatch schedule in short term. WASP is also incapable of visualizing the daily cycling pattern. The proposed model can be used for even very short term i.e. day ahead or hours ahead dispatch scheduling. It can also build up on results of WASP and predict the dispatch schedule of a representative day of the future.

Table 1 - Variables Used in the Proposed Model

In.	Description	Symbol	Source
1	Empirical data of demand at time t on the peak day of the reference year (peak day load curve) in MW	$D_p(t)$	Utility
2	Annual energy consumption of the reference year GWh	E_r	Utility
3	Projected annual energy requirement in GWh	E_T	Utility
4	Peak demand of k^{th} day of the reference year in MW. k=1,2...365	M_k	Utility
5	Total installed capacity of i^{th} plant on the merit list[9].	T_i	Utility
6	Incremental cost of the i^{th} plant on the merit list	C_i	Utility
7	Commissioning year of each plant.		Utility
8	Decommissioning year of each plant		Utility
9	Historical data of monthly energy and dispatchable capacity of the hydropower system in GWh (present and projected)		Utility
10	Run-of-the-river hydropower plants		Utility
11	Maximum load share allowed for a single generator	L	Utility
12	Hydrological condition to be analysed.		User
13	Reference year	y_0	User
14	Analysed year	y_x	User
15	List of all available plants		WASP

4. Proposed Model

4.1 Required Data

In the equation that follow;

$$t = \begin{Bmatrix} \text{time of the day in hours typically} \\ \text{starting at 0000h and ending at 2400h} \end{Bmatrix}$$

$$\Delta t = \begin{Bmatrix} \text{Differential unit of time} \\ \text{typically 30 minutes} \end{Bmatrix}$$

The proposed algorithm uses data published in Long Term Generation Expansion Plan (published by Ceylon Electricity Board) and some other additional data.

4.2 Availability of Plants

The algorithm requires details of power plants as given in Table 1. The algorithm takes in the power plants that are online at the time of analysis. In case of simulating plant outages other than scheduled retirements of plants, changes can be made manually.

4.3 Generating the Load Curve of a Representative Average Day

The algorithm accepts any daily load curve defined by the user. The user can analyse operation patterns and effects of any load curve of interest. The implemented software analyses daily load curves of 30-minute resolution starting from 0000h of the representative day of the reference year. For the purpose of future projections of current trend of load curves, a representative load curve of an average day of the reference year, is generated. The reference year is ideally the latest year of which the data 1 – 3 of Table 1 is available.

The peak day load curve is adjusted to match the average peak of the year.

$$\bar{M} = \frac{1}{365}\sum_{k=1}^{365} M_k \qquad (1)$$

$[k = 1,2,3 \ldots]$

Let $D_1(t)$ be an intermediate load curve adjusted to match the average peak of the year.

$$D_1(t) = D_p(t) - \{\max[D_p(t)] - \bar{M}\} \qquad (2)$$

The mean energy consumption of an average day is;

$$\bar{E}_{dx} = \frac{E_T}{365} \qquad (3)$$

Let D_2 (t) be the load curve function of the representative day of the reference year matched with average daily energy.

$$D_2(t) = D_1(t) + \alpha[\bar{M} - D_1(t)] \qquad (4)$$

Where α is a factor determined, subject to

$$\sum_{t=0000\text{h}}^{2400\text{h}} D_2(t) = \overline{E_d} \qquad (5)$$

The implemented MS Excel spreadsheet uses the Goal Seek function to find α.

This way, the adjusted $D_1(t)$ load curve is scaled down or scaled up to match the average daily energy consumption.

Alternative methods can be applied to determine a fair representative load curve.

Projecting the reference year representative load curve to the year to be analysed.

By means of government policies and development strategies the LTGEP provides a projected annual energy demand of the next 15 years.

Average daily energy generation requirement of the year x is given by $\overline{E_{dx}}$ in GWh.

$$\overline{E_{dx}} = \frac{\begin{pmatrix} \text{Total Energy Requirement} \\ \text{of Year } x \text{ in GWh} \end{pmatrix}}{365} \qquad (6)$$

The algorithm scales up the reference year representative load curve $D_2(t)$ by an annual growth rate r which is determined subjected to;

$$\sum_{t=0000\text{h}}^{2400\text{h}} D_2(t) \times (1+r)^{y_x - y_0} \times \Delta t \times \frac{1}{1000} = \bar{E}_{dx} \qquad (7)$$

Goal Seek function is used to find r.

The growth rate r implies a constant demand growth rate in all years between the reference year (y_0) and the analysed year (y_x).

4.4 Determining the Base Load

Run-of-the-river hydropower plants and the allowable minimum loading level of the coal power plants are considered to be the mandatory loading conditions. It is assumed that the coal plants are not kept as standing reserves and not subjected to daily cycling.

Minimum coal power, w, dispatched in the base load is given by;

$$w = \begin{pmatrix} Total\ installed \\ coal\ power\ in\ line \end{pmatrix} \times \begin{pmatrix} minimum \\ allowable \\ loading\ \% \\ of\ coal\ plants \end{pmatrix} \quad (8)$$

Run-of-the-river hydropower capacity, v, is determined by scaling down the total installed run-of-the-river hydropower capacity by a factor β determined by the hydrological condition of the analysed representative day.

$$v = \begin{pmatrix} Total\ runoff\ river\ hydropower \\ installed\ capacity \end{pmatrix} \times \beta \quad (9)$$

Mandatory loading level b in MW,

$$b = v + w \quad (10)$$

This is a constant and will fill up the load profile at the bottom as shown in the Figure 3.

Rest of the demand is first supplied by the remaining hydro energy e_{ph} (i.e. hydropower that is not run-of-the-river) for the day.

The peak hydropower component *p(t)* in MW is determined by;

$$p(t) = \frac{[d(t) - b]^{\gamma}}{\sum_{t=0000h}^{2400h}[d(t) - b]^{\gamma}} \times e_{ph} \times \frac{1}{\Delta t} \times 1000 \quad (11)$$

Initial value of γ, γ_0=0. This initial solution implies that the hydro energy is dispatched proportional to the demand that is not met by the mandatory dispatch, given by [*d(t)*-*b*].

γ is iteratively varied so that the operating cost of the system (incurred on the thermal plants) is minimized. The exponential distribution of peak hydro energy is that it is utilized the most when the demand is the highest.

4.5 Dispatching the Thermal Plants

In economic dispatch of thermal power plants, an incremental cost is calculated for each plant. The incremental cost reflects the fuel cost of each plant. It determines the merit order of thermal power plants according to which the plants are being dispatched. The most expensive plants are dispatched when the less expensive plant cannot supply the increased demand. The more expensive plants are the first to be stopped as the demand reduces unless there are other constraints in cycling of a thermal power plant in regular intervals.

The merit order is essential for this assignment. The following algorithm is implemented to achieve the lowest operating cost of the system.

Let G_i be the i^{th} generator in the merit order and *N-1* is the number of thermal power plants in line at the time of analysis.

G_N is a hypothetical generator whose representative incremental cost is an abnormally high penalty cost. This penalty cost avoids G_N being dispatched whenever the installed capacity is sufficient. In case the installed capacity is not sufficient, the total operating cost that is minimized is an abnormally high value contaminated by the penalty cost of G_N.

With initial condition i=1, the generator G_i is loaded to $l_i(t)$ subject to:

$$l_i(t) \le T_i$$

$$l_i(t) \le L$$

where, T_i = Available capacity of G_i

L = Maximum load share of a single generator

$$\sum_{j=1}^{i} l_j(t) \le d(t) - p(t) - b \quad (12)$$

Increment *i* by 1 up to m where,

$$\sum_{i=1}^{m} l_i = d(t) - p(t,\gamma) \quad (13)$$

Then the total cost of the system C_{total} is given by;

$$C_{total} = \sum_{t=0000h}^{2400h} \sum_{i=1}^{n} C_i l_i(t,\gamma) \quad (14)$$

γ is found to minimize C_{total}. The implemented MS Excel spreadsheet uses the Solver function to minimize C_{total} by changing γ.

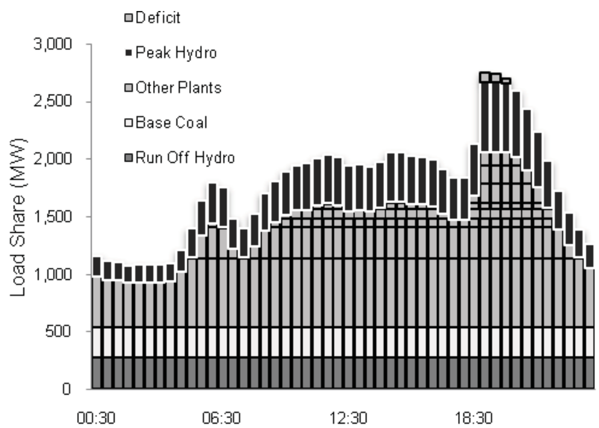

Figure 3 - Sample Results of the Proposed Model

Table 2 -Available Hydro energy in GWh in Different Rainfall Conditions in Months of the Year

Month	Very Wet	Wet	Med.	Dry	Very Dry	Avg.
1	457.8	383.9	350.1	367.3	336.9	379.2
2	406.9	292.7	285.1	274	265.2	304.8
3	384	320.8	268.3	248.5	237.8	291.9
4	269.4	303.5	249.7	237.8	213.8	254.9
5	487.7	413.4	367.7	338.7	290.5	379.6
6	501.9	498.1	431.6	334.6	291.6	411.6
7	510.2	542.4	447.6	365.8	316	436.4
8	460.4	442.9	374.3	286.8	261.3	365.1
9	507.8	392.9	373	246.4	297.9	363.6
10	426.9	416.5	415.4	402.9	308.7	394.08
11	510.5	458.1	416.6	416.9	289.4	418.3
12	500.1	412.9	399.7	325.8	248.3	377.4
Tot	**5423**	**4878**	**4379**	**3845**	**3357**	**4376**

4.6 Hydrological Calculations

The availability of hydropower depends on the hydrological condition and the water release constraints of the time of consideration. The water release constraints depend on the agricultural water usage patterns which again depend on the hydrological conditions. The historical data of availability of hydro energy and dispatchable plant capacity for different hydrological conditions is summarized in**Table** 2.

Similar data is projected for prospective hydropower plants. The amount of average dispatchable hydropower as a percentage of total installed hydropower capacity, β is calculated as shown in the following sample calculation.

Table 3 - Total Dispatchable Hydropower in MW in Different Rainfall Conditions during the Months of a Year

Month	Very Wet	Wet	Med.	Dry	Very Dry	Avg.
1	989.4	939.8	948.9	959.5	948.1	957.1
2	996.2	961.9	965.4	967.3	936.7	965.5
3	1032.6	1019.5	1017.3	999.6	984.5	1010.7
4	1027.4	1023.7	974.8	947.7	917.4	978.2
5	1094.6	1077.2	1044.2	992.3	965.8	1034.8
6	1074.4	1075.8	1031.3	963.6	899.3	1008.9
7	1089	1082.8	1052	960.8	913.1	1019.5
8	1034.5	1028.7	1002.6	908.2	829.1	960.6
9	1036.9	1025.5	1006.9	802.3	799.4	934.2
10	1035.7	1008.6	1023.5	986.9	904.6	991.9
11	1042.5	1023.3	1000.7	987.9	941.2	999.1
12	999.2	987.1	979.7	967.3	943.1	975.3
Avg.	**1037.7**	**1021.2**	**1003.9**	**953.6**	**915.2**	**986.3**

Consider “wet” condition

Let H_i be the i^{th} plant of the list of hydropower plants.

Let *P(month)* be the relevant dispatchable hydropower capacity of a given month as given in **Table 3 -**

$$\beta = \frac{\frac{1}{12}\sum_{Jan}^{Dec} P}{\sum_{i}^{n} T_i} \quad (15)$$

Run-of-the-river hydropower plants are assumed to be generating electricity at a constant power b MW throughout the day. Remaining energy after run-of-the-river energy portion is given by the following relationship

Let e_h be the total hydro energy available for a day in GWh. Let e_{ph} be the remaining hydro energy after run-of-the-river energy in GWh.

$$e_{ph} = e_h - \frac{b \times 24}{1000} \tag{16}$$

β ratio for a custom hydrological scenario can be derived by giving the daily hydro energy and dispatchable power as inputs.

5. Implementation of the Proposed Model

The proposed model is implemented on Microsoft Office Excel 2007. The inbuilt formulae and functions such as Goal Seek and Solver were effectively used to implement the basic structure of the algorithm. Iterative optimization is done by custom macros. In cases of implementing the iterative analysis for longer planning windows, it was observed that the programme consumes a few minutes but an analysis with economic benefits for a period of 30 years took only less than 5 minutes on a personal computer with an Intel® Core2Duo™ processor.

Data entry, checking errors in the input data, debugging the VBA macro code and making alterations in the code using Microsoft Office Excel 2007 or an equivalent spreadsheet software is very user-friendly and takes much less time than using WASP. So, the proposed model implemented on simple and popular software makes it very useful in quick analysis. Graphical representations of the results arrived at can also be directly generated. Thus abnormal behaviour, deficits and errors in results can be viewed instantly.

6. Examples of Adaptation of the Algorithm

- The proposed algorithm can be used by System Operators of utilities for day ahead planning of the most economical dispatch. Water release constraints, plant availability and exact hydrological conditions can be fed in and the representative dispatch schedule can be visualized. If sufficient data is available, by simple changes in the algorithm and its code, even an hour ahead economic dispatch schedule can be achieved. In a power system, whose dispatch decisions are not automated, this tool is a cost effective method to determine the minimum cost dispatch schedule.

- The proposed algorithm can be used to analyse the projected effect of a new technology or a new power source that does not appear in the online plant list at the time of consideration OR of an existing thermal power plant. The financial benefits, daily loading patterns and utilization of the new plant can be derived by iterating the algorithm for the years which are in the analysis window.

- The proposed algorithm can determine the size and time of a new power source (e.g. pump storage power plant) by evaluating the benefits and utilization of the introducing power plant. The basis of the analysis would be the daily system operating cost. It can be analysed with the probability of different expected hydrological conditions within the planning window. Rough capital costs, discount rates, price escalations can be incorporated in the analysis by a simple changes in the codes and formulae used in the spreadsheet application.

- The proposed algorithm can be adapted to analyse the expected daily cycling patterns of a thermal power plant whose start-up cost is considerably high. The analysis can determine if operating the respective power plant throughout the day would be more beneficial than using it only as a peaking power plant. OR it can determine if operating a different power plant whose incremental cost is higher but the start-up cost is lower, so that the total system operating cost is less as it is used only for a shorter period during the peak demand.

7. Summary and Conclusions

WASP is an advance software developed by IAEA for the purpose of assisting power system expansion planning. The computing constraints on using daily load curves for a large planning window has lead to design WASP to consider only the load duration curve. The results obtained by WASP have been accepted and relied upon by utilities like Ceylon Electricity Board. The limitations of WASP as described in Section 2 have restricted researchers and planners to consider additions and alterations to the power system expansion plans.

The daily load curve approach of the proposed model allows the users to visualize the daily operation patterns of different power plants. This data is important to the system operator, power plant operators and managers, policy makers and power system planning authorities. The model can be used to schedule the dispatch to arrive at the least daily operational cost. It can also be adapted to arrive at the least environmental cost of running the system if the environmental cost of each thermal plant is available.

The proposed model in this paper is a user friendly algorithm easily implemented on available spreadsheet software. The model depends on results obtained from proper runs of WASP, as given in Long Term Generation Plans of CEB. The algorithm can also be adapted for various purposes so that different planning scenarios can be analysed.

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