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論 文
34～8～2

Optimal Generation Planning Including Pumped-Storage Plant Based on Analytic Cost Function and Maximum Principle

朴 永 文*·李 鳳 容**
(Young-Moon Park · Bong-Yong Lee)

요 약

장기전원 계획은 방대한 자금규모를 요하는 주요한 과제로서 경제성의 추구는 절대적이라고 해야할 것이다. 과제의 중요성에 비추어 많은 연구가 발표되어 왔으나, 아직도 충분한 개선의 여지가 남겨져 있다.

본 논문은 최대원리를 응용하여, 최근에 발표된 박영문 교수의 해석적 함수에 의한 모델링이 화력만을 허용하고 있는 점을 보완 발전시켜 양수발전을 포함하도록 확장하였다. 또한 일반적으로 사용되고 있는 확률적 신뢰도 지수 대신에 공급지장비를 해석적으로 다룰 수 있도록 함수를 운전비에 포함시켰다.

최대원리의 해는 경사법에 의하였으며, 다단계의 해를 1단계식 처리하지 않고 모든 제어 변수를 수리계획법에서와 같이 한번의 반복 계산과정 중에서 한꺼번에 계산 처리하였다.

본 논문은 실규모의 계통에서 충분히 검토가 되었으며, 그 결과를 기존의 타 방법에 의한 결과와 비교하였으며, 그 유용성이 충분히 실증되었다.

금후 본 논문에서 제시된 방법은, 실제의 최적장기전원 계획에서 본격적으로 활용될 것이 기대된다.

Abstract

This paper proposes an analytic tool for long-term generation expansion planning based on the maximum principle. Many research works have been performed in the field of generation expansion planning. But few works can be found with the maximum principle.

A recently published one worked by Professor Young Moon Park et al. shows remarkable improvements in modeling and computation. But this modeling allows only thermal units.

This paper has extended Professor Park's model so that the optimal pumped-storage operation is taken into account. So the ability for practical application is enhanced. In addition, the analytic supply-shortage cost function is included.

The maximum principle is solved by gradient search due to its simplicity. Every iteration is treated as if mathematical programming such that all controls from the initial to the terminal time are manipulated within the same plane.

Proposed methodology is tested in a real scale power system and the simulation results are compared with other available package. Capability of proposed method is fully demonstrated.

It is expected that the proposed method can be served as a powerful analytic tool for long-term generation expansion planning.

*正 會 員：서울大 工大 電氣工學科 教授·工博
**正 會 員：弘益大 工大 電氣工學科 教授·工博
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1. Introduction

During the past decade, numerous optimal generation expansion planning models have been proposed[1)-19)], and some of them found the actual implementation for utility plannings[2),5),9)-11),14)-16)]. Generation planning involves finding a generation expansion and operating policy that minimizes present worth cost while meeting projected demands and other imposed constraints such as technical, economical, environmental and other uncertainties. The reliable power supply to the consumers at the lowest possible cost is ensured, and moreover, such a plan is searched over a far horizen. Since planning dicisions involve considerable investments and operating costs and commit utilities to at least 10 years into the future, better and more efficient optimization techniques are always worth to be paid continuous attention.

Reviewing the existing major mathematical formulations for generation expansion planning models, it seems to be able to categorize

a) linear programming formulations[1)-5),17),18)],
b) nonlinear programming formulations[6),7)],
c) dynamic programming formulations[5),8)-11)],
d) dynamic expansion strategy using optimal control theory[12)-15)], and
e) others[16),17)].

Every formultion has its inherent advantages and shortcomings, but a), c) and d) seem to be in wide acceptance.

In linear programming formulations which have been developed from the early days due to its simplicity and easy access to standard algorithms, there is a major difficulty of problem size increase when increasing planning period and increasing time steps of discrete load duration curve. In order to reduce problem size and exploit LP's advantages, decomposition techniques are recently proposed[5),18),19)].

Dynamic programming formulations have been found to be in popular use of which one is known with the name of "WASP package" which is developed by T.V.A. in U.S.A. Dimensionality problem forces users to have computational burden.

Another approach with dynamic expansion strategy is to use optimal control theory and implemented in "Le Modele National d'Investissement (MNI)" package which is developed by E.D.F. in France. The load variations with discrete time steps and plant capabilities are represented with Gaussian random variables. This modeling allows to include predicted load growth uncertainties and the solution of the model gives the optimal plant mix expectations, the use value of equipment and other marginal cost informations. Nevertheless, it has three major shortcomings such that a) discretization of Gaussian probability density functions of random loads and random plant capabilities brings higher computational burden for convolution, b) convolution of loads and plant capabilities is a only rough approximation and c) the optimal pumped-storage plant operation is not achieved.

Advanced analytic modeling to use optimal control theory is recently published[15)] by professor Young Moon Park et al. With the analytic cost function and the imposed reliabilty constraint, the optimal plant mix expectation is efficiently searched. However this modeling includes only thermal units.

This paper addresses a dynamic expansion strategy using optimal control theory. The above Park's model is extended to include optimal pumped-storage operation and instead of reliability constraint analytic supply-shortage cost is introduced into the operation simulation.

The validity and effectiveness of the proposed approach is tested in a real scale power system and the results are compared with other avilable methods, mainly with those of MNI.

2. Production Costing Simulation

For the production costing simulation, this paper derives an analytic operation cost function which is the objective function to be minimized combined with the analytic supply-shortage cost function given in[30)], assuming the Gaussian distributed random loads within discrete time steps[15),20)]. The pumped-storage plant will give some complexity in the simulation.

The pumped-storage plant operation is justified when economy between pumping (incurring cost) and peak-shaving (saving cost) is expected. This economic justification is searched for example in WASP such that the suitable generation position is repeatedly searched on ELDC (Effective Load Duration Curve) until the cost balance between pumping and generation (peak-shaving) is obtained. During these repeated process, convolution and deconvolution are also repeatedly excercised. The chronological loss with a single load duration curve may lead to a insuffi cient result. Another example used in MNI is such that pumping is done up to the pre-selected economically prospective generation level in a specific convoluted case from both discretized load and generation capability, and the peak-shaving operation is performed at the same time. Such cases are summed multiplied by their probabilities. However, the pre-selected generation level cannot reflect the true pumping level. In addition, the pre-selected generation level itself is not given accurately due to difficulties of accurate convolution. Nevertheless, WASP and MNI are known to be powerful tools for generation planning.

This paper proposes quite a different and efficient analytic approach to the optimal pumped-storage plant simulation. Some difinitions are required:

(Definition 1) Pumping level is defined such that the assumed supplied demand level including pumping load is economically prospective.

(Definition 2) Peak-shaving level is defined such that the assumed supplied demand level above which hydro-generation is desired.

It is noted that pumping can only be done when generation surplus is available and hydro-generation in peak-shaving is economical when generation with higher fuel costs could be reduced. Thus, the best economic operation policy is pumping to pumping level and generation above peak-shaving level. This concept is also indicated in Fig. 1.

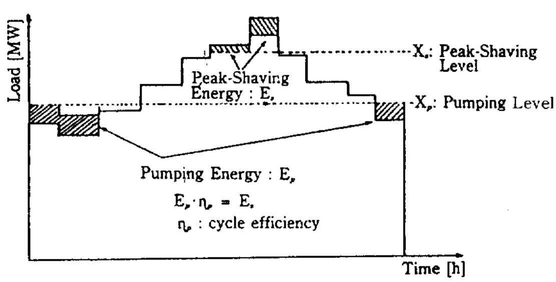

Fig. 1. Concept of pumping and peak-shaving

Supplied Demand and Operation Cost Including Pumping Case

Supplied demand by pure thermal units can be obtained through various simulation models[16)-26)], but the one developed by Professor Park et al.[15),20)] is especially interesting since it is expressed simply by an analytic cost function, and therefore the efficiency and accurateness in modeling are greatly enhanced. This paper follows also the same philosophy as the Park's. For this, an assumption is introduced[15),20)]:

(Assumption 1) The capability of a generation group is assumed to have Gaussian distribution with its statistical mean and variance.

It is assumed that the random variable of pumping and peak-shaving, y_p, has also Gaussian distribution. Due to y_p, supplied demands of thermal units will be increased and due to $-y_p$, thermal units will deliver less energies. Apparent load would be increased for pumping and decreased for peak-shaving.

Thus, three kinds of supplied demands are encountered such that

$$^jZ_P = \min(L_P, {}^jy)\,[\mathrm{MW}] \text{ for } -\infty \le {}^jZ_P \le X_P \quad (1)$$

$$^jZ_L = \min(L, {}^jy)\,[\mathrm{MW}] \text{ for } X_P \le {}^jZ_L \le X_S \quad (2)$$

$$^jZ_S = \min(L_S, {}^jy)\,[\mathrm{MW}] \text{ for } X_S \le {}^jZ_S \le +\infty \quad (3)$$

where

^jy : the plant capability up to j-th group accumulated,

^jZ_P : the supplied demand with L_p and ^jy,

^jZ_L : the supplied demand with L and ^jy,

^jZ_S : the supplied demand with L_s and ^jy.

$$L_P = L_\Delta + y_P \quad (4)$$

$$L_S = L_\Delta - y_P \quad (5)$$

L_Δ : the random load

$\Delta = i, s, k$: index of year i, season s and time step k

$i = 1, 2, \cdots\cdots, N$

$s = 1, 2, \cdots\cdots, S$

$k = 1, 2, \cdots\cdots, K$

Additional impulse terms should be taken into account as seen from Fig. 2.

$$^jZ_{xp} = \min(X_P, L_P)\,[\mathrm{MW}] \text{ for } X_P \le {}^jZ_{xp} \le X_P + y_P \quad (6)$$

$$^jZ_{xs} = \min(X_S, L_S)\,[\mathrm{MW}] \text{ for } X_S - X_P \le {}^jZ_{xs} \le X_S \quad (7)$$

$$\text{and } {}^jy \ge X_P \text{ or } X_S$$

where

$^jZ_{xp}$: the supplied demand with L_p and ^jy for the pumping impulse.

$^jZ_{xs}$: the supplied demand with L_s and ^jy for the peakshaving impulse.

Since y_p is random, $X_p + y_p$ and $X_s - y_p$ levels would

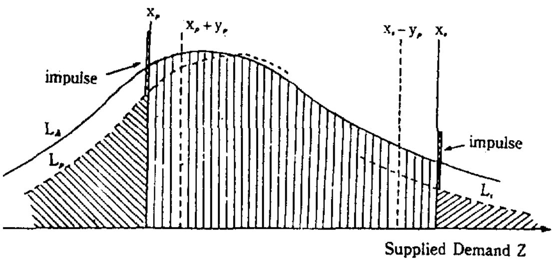

Fig. 2. Load impulse at x_p and x_s.

be overlapped. However, this overlapping does not substantially alter results and thus overlapping may be neglected. The expected supplied demand including pumping and peak-shaving is given by with dropping index j for the simplicity.

$$\begin{aligned}
\overline{P}_\Delta =& \int_{-\infty}^{X_P} Z_P\, f_{zP}(Z_P)\, dZ_P + \int_{X_P}^{X_S} Z_L\, f_{zL}(Z_L)\, dZ_L \\
&+ \int_{X_S}^{\infty} Z_S\, f_{zS}(Z_S)\, dZ_S + \int_{-\infty}^{\infty} \{ \int_{X_P}^{X_P+y_P} X_P \cdot f_{LP}(L_P) \\
& dL_P \int_{X_P}^{\infty} f_y(y)\, dy \} f_{y_P}(y_P)\, dy_P + \int_{-\infty}^{\infty} \{ \int_{X_S-y_P}^{X_S} X_S \cdot f_{LS} \\
& (L_S)\, dL_S \int_{X_S}^{\infty} f_y(y)\, dy \} f_{y_P}(y_P)\, dy_P \\
=& \overline{L}_P F_{L_P}(X_P) F_y(X_P) + [\overline{L}_P F_{L_P}(X_P) - \\
& - \sigma_{L_P}^2 f_{L_P}(X_P)][1 - F_y(X_P)] + [\overline{y} F_y(X_P) \\
& - \sigma_y^2 f_y(X_P)][1 - F_y(X_P)] - (\overline{L}_P - \overline{y}) LOLP(X_P) \\
& - \sigma_{z_P}^2 f_{zP}(O) F_{yL_P}(X_P) + \overline{L} F_L(X_S) F_y(X_S) \\
& + [\overline{L} F_L(X_S) - \sigma_L^2 f_L(X_S)][1 - F_y(X_S)] \\
& + [\overline{y} F_y(X_S) - \sigma_y^2 f_y(X_S)][1 - F_L(X_S)] \\
& - (\overline{L} - \overline{y}) LOLP(X_S) - \sigma_z^2 f_z(O) F_{yL}(X_S) \\
& - \overline{L} F_L(X_P) F_y(X_P) - [\overline{L} F_L(X_P) \\
& - \sigma_L^2 f_L(X_P)][1 - F_y(X_P)] - [\overline{y} F_y(X_P) \\
& - \sigma_y^2 f_y(X_P)][1 - F_L(X_P)] + (\overline{L} - \overline{y}) LOLP(X_P) \\
& - \sigma_z^2 f_z(O) F_{yL}(X_P) + \overline{L}_S [1 - F_{LS}(X_S) F_y(X_S)] \\
& - [\overline{L}_S F_{LS}(X_S) - \sigma_{LS}^2 f_{LS}(X_S)][1 - F_y(X_S)] \\
& - [\overline{y} F_y(X_S) - \sigma_y^2 f_y(X_S)][1 - F_{LS}(X_S)] \\
& - (\overline{L}_S - \overline{y}) LOLP'(X_S) - \sigma_{zS}^2 f_{zS}(O) F_{yLS}(X_S) \\
& + X_P [F_{zP}(O) - F_{LP}(X_P)][1 - F_y(X_P)] \\
& + X_S [F_{zS}(O) - F_{LS}(X_S)][1 - F_y(X_S)] \qquad (8)
\end{aligned}$$

where

$F_x(\alpha)$: the proability distribution of x from $-\infty$ to α.

$f_x(\alpha)$: the probability density value of x at α.

σ_x^2 : the variance of x.

$\bar{x}$: the mathematical expectation of x.

$$f_z(o) \triangleq \frac{1}{\sqrt{2\pi}\,\sigma_z} \exp\{-\frac{(\overline{L} - \overline{y})^2}{2\sigma_z^2}\} \qquad (9)$$

$$\sigma_z^2 = \sigma_{L\Delta}^2 + \sigma_y^2$$

$$F_{y_L}(\alpha) \triangleq \frac{1}{2} + \mathrm{erf}\,[\frac{\alpha - (\overline{y}\sigma_L^2 + \overline{L}\sigma_y^2)/\sigma_z^2}{\sigma_y \sigma_{L\Delta} / \sigma_z}] \qquad (10)$$

$$LOLP(\alpha) \triangleq \int_{-\infty}^{\alpha} F_y(Z) f_L(Z)\, dZ \qquad (11)$$

$$LOLP'(\alpha) \triangleq \int_{\alpha}^{\infty} F_y(Z) f_L(Z)\, dZ \qquad (12)$$

$$F_{X\alpha}(o) \triangleq \frac{1}{2} + \mathrm{erf}\,[\frac{\overline{y}_P + \alpha - \overline{L}}{\sqrt{\sigma_{L\Delta}^2 + \sigma_{yP}^2}}] \qquad (13)$$

Once the supplied demand expectations of every time step are determined from (8), the total operation cost, $\overline{f}_T$, for the unit time interval is given by

$$\overline{f}_T = \sum_K t_K \sum_j (C^j - C^{j+1})^j\, \overline{P}_{\Delta K} + \sum_K t_K \overline{f}_{dk} \quad [S] \qquad (14)$$

where

$\overline{f}_{dk}$: the expected supply-shortage cost in k-th time step.

There are an equality and an inequality constraint for pumped-storage plant operation. These are

$$\overline{E}_S = \eta_P \overline{E}_P \qquad [MWh] \qquad (15)$$

$$\overline{E}_P \le E_P^{max} \qquad [MWh] \qquad (16)$$

where

E_p^{max} : the maximum allowable pumping energy [MWh],

$\overline{E}_p$: the expected pumping energy [MWh],

$\overline{E}_s$: the expected peak-shaving energy [MWh],

η_p : the cycle efficiency [p.u.],

C^j : the average fuel cost [\$/MWh]

j = 1, 2, ..., n : plant type

$C^j < C^{j+1}$ and $C^{n+1} = 0$.

Finally, the expected annual generation cost $\overline{F}_{ai}$ is given by

$$\begin{aligned}
\overline{F}_{ai} &= \sum_{S=1}^{S} n_S \overline{f}_{TS} \\
&= \sum_{S=1}^{S} n_S \{\sum_K t_K \sum_{j=1}^{n} (C^j - C^{j+1})^j\, \overline{P}_{\Delta K} + \sum_K t_K \overline{f}_{dK} \qquad (17)
\end{aligned}$$

wher

$\overline{f}_{TS}$: the expected seasonal generation cost

Optimal operation Including Pumped-Storage Plant

It is observed from equation (14) and (15) that the operation cost $\bar{f}_T$ is a function of X_p and X_s, provided that constraints are satisfied. Hence the optimal pumped-storage plant operation can now be formulated as

$$\min \bar{f}_T = \bar{f}_T(X_P, X_S)$$
$$\text{subject to} \quad g(X_P, X_S) = \eta_P \bar{E}_P - \bar{E}_S = 0$$
$$X_P^{min} \leq X_P \leq X_P^{max}$$
$$X_S^{min} \leq X_S \leq X_S^{max} \qquad (18)$$

This is a simple mathematical programming problem and can easily be solved. The augmented objective function is defined as

$$L = \bar{f}_T + \lambda g + w(X_P - X_P^{max}) + v(X_P - X_P^{min}) + u(X_S - X_S^{max}) + t(X_S - X_S^{min}) \qquad (19)$$

where

λ, w, v, u, t: Largrangian multipliers

Kuhn-Tucker optimal condition gives

$$\frac{\partial L}{\partial X_P} = \frac{\partial \bar{f}_T}{\partial X_P} + \lambda \frac{\partial g}{\partial X_P} + w + v = 0$$

$$\frac{\partial L}{\partial X_S} = \frac{\partial \bar{f}_T}{\partial X_S} + \lambda \frac{\partial g}{\partial X_S} + u + t = 0$$

$$\lambda g = 0 \qquad (20-1)$$
$$w(X_P - X_P^{max}) = 0$$
$$v(X_P - X_P^{min}) = 0$$
$$u(X_S - X_S^{max}) = 0$$
$$t(X_S - X_S^{min}) = 0$$

If inequalities are handled seperately in iteration process of computation, there remains only an equality constraint and the optimal conditions is reduced to

$$\frac{\partial \bar{f}_T}{\partial X_P} + \lambda \frac{\partial g}{\partial X_P} = 0$$
$$\qquad (20-2)$$
$$\frac{\partial \bar{f}_T}{\partial X_S} + \lambda \frac{\partial g}{\partial X_S} = 0, \quad g = 0$$

Equality can be solved with the given X_p and the dependent X_S. Under this condition λ is given by

$$\lambda = -\frac{\partial \bar{f}_T}{\partial X_S} \Big/ \frac{\partial g}{\partial X_S} \qquad (21)$$

With the substitution of eq. (21) into (20-2), the gradient of X_P is obtained

$$\frac{\partial L}{\partial X_P} = \frac{\partial \bar{f}_T}{\partial X_P} - \left(\frac{\partial \bar{f}_T}{\partial X_S} \Big/ \frac{\partial g}{\partial X_S}\right) \frac{\partial g}{\partial X_P} \qquad (22)$$

Improved pumping level is determined from

$$X_P^{new} = X_P^{old} - \alpha \frac{\partial L}{\partial X_P} \qquad (23)$$

where

α : step size

The marginal capacity cost in operation can also be derived from (20-2) and the formula for this is given in 30)

3. Generation Expansion Planning

To the global investment planning, multistage maximum principle is applied. The problem is finding the sequence of control (units to be newly added) u(0), u(1), ..., u(N-1) to minimize the objective function subject to constraints.

The present worth method is applied on the total objective cost function. For this, the investment cost is assumed to incur year initials and operation costs year middles. Beyond the horizen year, the demand is assumed to be constant to infinity.

The state vector (accumulated capacity) is defined as

X(k) : capacity of k-th year

and the control vector as

U(k) : capacity addition in k-th year

X(k) and U(k) have n components from 1 to n and the component is denoted by i. Then the state equations describing the evolution of a power system take a form

$$X_i(k+1) = X_i(k) + u_i(k), \; i = 1, 2, \cdots\cdots, n \qquad (24)$$

$X_i(0)$ = given; the existing facilities.

When the investment cost in k-th year is denoted I^k, the operation cost F^k, the supply-shortage cost G^k and the horizen year cost S, then the total objective cost function becomes the summation of them and the problem of generation expansion can be defined as follows:

$$\min \sum_{k=0}^{N-1} \{I^k[u(k)] + F^k[X(k), U(k)] + G^k[X(k), U(k)]\} + S[X(N)] \qquad (25)$$

subject to

$$X(k+1) = X(k) + U(k)$$
$$U(k)^{min} \leq U(k) \leq U(k)^{max}$$
$$X(0): \text{ given}$$
$$X(N): \text{ free}$$

The Hamiltonian is defined as

$$H^k = I^k + F^k + G^k - \lambda(k+1)[X(k) + U(k)] \qquad (26)$$

then, the adjoint system is given by

$$\lambda(k+1) = \lambda(k) + \frac{\partial F^k}{\partial X(k)} + \frac{\partial G^k}{\partial X(k)} \qquad (27)$$

$$\lambda(N) = -\frac{\partial S}{\partial X(N)} \tag{28}$$

Eq. (27) can be solved from λ(N) or is given by

$$\lambda(k) = -\sum_{m=k}^{N-1}\left\{\frac{\partial G^m}{\partial X(m)} + \frac{\partial F^m}{\partial X(m)}\right\} - \frac{\partial S}{\partial X(N)} \tag{29}$$

This can be interpreted as marginal benefit, because all cost incrementals are negative.

Kuhn-Tucker optimal condition gives

$$\frac{\partial H^k}{\partial U(k)} = \frac{\partial I^k}{\partial U(k)} + \frac{\partial F^k}{\partial U(k)} + \frac{\partial G^k}{\partial U(k)} - \lambda(k+1) = 0 \tag{30}$$

Upon substitution of eq. (27) into (30), the following simpler form is obtained as

$$\frac{\partial I^k}{\partial U(k)} - \lambda(k) = 0 \tag{31}$$

It is noted that λ(k) is the marginal benefit and it is balanced with the marginal investment. In the Hamiltonian optimum, marginal investment and marginal benefit are equal. Moreover, it is the gradient of the objective function. If the balance has not been reached, further iteration is needed. For the gradient search, incremental controls are required.

$$\triangle U(k) = -\alpha \frac{\partial H^k}{\partial U(k)} = \alpha\left\{\lambda(k) - \frac{\partial I^k}{\partial U(k)}\right\} \tag{32}$$

then, the improved control is given by

$$U(k)^{new} = U(k)^{old} + \triangle U(k) \tag{33}$$

The major calculation in this modeling involves the marginal capacity cost in operation which is represented in eq. (29). Operation results deliver this informations. Thus the key of the problem lies on the efficient operation simulation.

The next major step is α-step determination. Very excellent and efficient optimal step size calculation is suggested by P. Lederrer[28].

4. Simulation Results

The proposed model is tested on a real scale power system and compared mainly with the results of MNI which are available from the previous study work[28].

4.1 Input Data

Two systems are interchangeably used according to necessity. System A is the prospective KEPCO's system, and system B indicates EPRI's synthetic system I.

Loads are summerized in Table 1.

Table 1. Load inputs.

Season \ Time-step			1	2	3	4	5	6	7
KEPCO LOADS [MW]	BASE YEAR I	I	7,637.02	7,325.82	6,802.71	6,658.44	5,727,29	5,354,16	5,283.46
		II	8,539.03	8,398.44	8,166.21	8,148.31	6,817.31	6,349.3	6,308.6
		III	8,518.91	8,169.29	7,702,92	7,636.19	6,439.91	6,025.94	5,950.75
		IV	8,896.65	8,896.65	8,107.52	7,877.67	6,653.84	6,239.03	6,164.7
	BASE YEAR II	I	11.983.08	11,690.68	11,133.98	10,378.00	8,654.04	8,065.89	7,913.29
		II	13,553.28	13,333,28	12,878,38	12,209,98	10,093.3	9,203,37	9,027.37
		III	13,157.33	12,838.48	12,476.1	11.584.0	9,562.2	8,918.02	8,759.12
		IV	13,775.98	13,445.78	13,114.2	11.998.0	9,981.1	9.254.22	9.097.05
	BASE YEAR III	I	18,253.64	17,809.63	16.964.93	15,942.01	13,178.6	12,285.4	12,053.2
		II	20,957.48	20,619.18	20.138.85	18.846.5	15,575.3	14.024.9	13,933.4
		III	20,126.8	19,482.98	19.090.74	17.569.5	14.508.8	13,533.8	13,292.6
		IV	20,892.0	20,392.5	20,018.08	18.187.0	15,040.3	14,036.0	13,797.7
EPRI LOADS (MW)			23,255.102	22,036.898	20,740.602	18,923.301	15,809.898	14,778.398	14,415.301
Time Duration [h]	KEPCO		1	3	5	7	5	2	1
	EPRI		1	8	3	5	2	3	2

Load variances are to be taken as 5 [%] to mean in KEPCO's case, and calculated from LDC in EPRI's case.

4.2 Operation Simulation

For pure thermal system, operational characteristics are compared with each other. One year or one season is selected as one operational test period. Table 2 shows the results for System B.

Table 2. Operational characteristics for system B.

(Period = 728 [h])

		Proposed Method (Pure thermal)	EPRI (Pure thermal)	Proposed Method (Pumping)	Remarks
Total Supplied Energy [GWh]		13,943.4	13,902.0	14,176.8	
Not Supplied Energy [GWh]		45.38	21.93	24.3	
LOLP [p.u.]		0.0374	0.03333	0.0218	
Supplied Energy by Group [GWh]	Nuclear	4,950.34	4,950.34	4,950.34	8,000[MW]
	Coal	6,656.00	6,431.45	6,917.56	11,200[MW]
	Oil	2,091.36	2,240.28	1,993.22	8,000[MW]
	Gas Turbine	245.70	279.88	167.08	4,800[MW]
	Pumping	−	−	148.64	1,000[MW]
Total Operating Cost [k$]		252,633	255,868	249,140	
Energy Mismatch[%]		−0.0011	−0.465		AREA of LDC = 13,988.94 [GWh]

The result of EPRI is based on the probabilistic simulation (cumulant method) with ELDC and every single unit, while the proposed method uses the discrete load duration curve and group generations. In case of pure thermal operation, the proposed method showed smaller energy mismatch. Pumping case is compared with the pure thermal operation. The increase of supplied energy by coal type plants and the decrease of supplied energy from plants with higher fuel cost have reduced the operation cost. Thus, the economy for pumping operation is evident, although the total supplied energy is greater than the pure thermal case.

4.3 Generation Expansion Results

As an optimal long-term generation expansion planning tool, the effectiveness and capability of the proposed method should fully be demonstrated. For this purpose, two Tables are provided.

Table 3 shows a 10-year planning case for the optimal investment. Both methods, the proposed and MNI, are compared with each other year by year. Any remarkable discrepancies are not found, but it is seen that MNI invests more pumped-storage plant, while the proposed method invests more coal type plants by the horizen year.

In Table 4, the optimal investment for a 15-year planning interval is summerized. Here, a major discrepancy between both methods is found in the investment of pumped-storage plant. MNI invests 2,500 [MW] by the year 2,001, while the proposed method invests only 1,100 [MW]. It is noted that the effect of the horizen year is noticeable from Table 3 and 4, in both methods, since it can be seen within the same planning interval from 1986 to 1996 that investments of coal type plant and pumped-storage plant of a 15-year planning interval differ from those of a 10-year planning interval.

Table 3. 10-year optimal investment.

Year	Demand [MW]	Reserve [%]		Nuclear [MW]		Coal [MW]		Pumped-storage [MW]		Present Worth [k$]		Remarks
		Proposed	MNI	Proposed	MNI	Proposed	MNI	Proposed	MNI	Proposed	MNI	
Initial				3816		2120		400				Other initials:
1986	10656	55.48	55.48	900	900	1000	1000	–	–	3655550	3649179	Coal = 850
1987	11679	54.82	56.0	900	900	613	705	–	–	2931590	3001431	[MW]
1988	12749	51.41	53.65	1000	1000	222	266	–	–	2480390	2490945	Oil = 5791
1989	14014	44.88	47.39	1000	1000	–	–	–	–	2136640	2120781	Combined
1990	15340	45.39	48.09	2000	2000	–	–	–	–	2981090	2969619	= 920
1991	16796	44.1	47.53	2000	2000	–	–	·	·	2685280	2677230	Gas Turbine
1992	18317	43.05	46.89	2000	2000	–	–	–	–	2433170	2427665	= 100
1993	19977	41.18	45.33	2000	2000	–	–	–	·	2221570	2217750	
1994	21779	38.84	42.83	2000	2000	35	34	–	41	2056880	2063465	
1995	23744	38.14	41.09	2000	2000	561	284	–	108	2122430	2026108	
1996	25881	26.73	29.44	–	–	·	·	–	–	6788270	6702434	
Total Present Worth Cost [k$]										32,493,460	32,346,607	

Table 4. 15-year optimal investment.

Year	Demand [MW]	Reserve [%]		Nuclear [MW]		Coal [MW]		Pumped-Storage [MW]		Present Worth Cost [k$]	
		Proposed	MNI	Proposed	MNI	Proposed	MNI	Proposed	MNI	Proposed	MNI
Initial											
1986	10656	58.24	59.05	900	900	914	1000	–	–	3577140	3649336
1987	11670	56.83	58.39	900	900	555	650	–	–	2892010	2955486
1988	12749	53.20	54.79	1000	1000	214	236	–	–	2488050	2472826
1989	14014	46.50	47.95	1000	1000	–	–	–	–	2150050	2128781
1990	15340	46.88	48.20	2000	2000	–	–	–	–	2981470	2975783
1991	16796	45.80	47.26	1957	2000	–	–	–	–	2655580	2682288
1992	18317	44.14	45.95	1914	2000	–	·	·	–	2374990	2432065
1993	19977	41.91	44.15	1947	2000	–	·	–	63	2198380	2235132
1994	21779	39.35	42.38	2000	2000	–	–	–	212	2058480	2083159
1995	23744	36.24	40.46	2000	2000	–	–	–	342	1903060	1949174
1996	25881	32.72	38.29	2000	2000	–	42	–	398	1771510	1839755
1997	27984	31.69	38.61	2000	2000	504	613	–	385	1828810	1909215
1998	30260	31.21	38.77	2000	2000	798	826	94	377	1797120	1837632
1999	32723	33.00	39.13	2000	2000	1309	1170	506	366	1870970	1807641
2000	35384	35.99	40.17	2000	2000	2000	1886	600	375	1926030	1821679
2001	38200	25.87	29.84	–	–	–	–	–	–	5990660	5730482
Total Present Worth Cost [k$]										40,472,310	40,510,434

The total present worth costs are comparable each other, showing 32,493,456 [k$] in the proposed method and 32,346,607 [k$] in MNI for a 10-year planning case, and 40,472,310 [k$] and 40,510,434 [k$] for a 15-year planning case.

The comparison of the computing time with Eclipse MV-8000 showed that the proposed method is more favorable by 1/4 than MNI for a 10-year planning case and by 1/8 for a 15-year planning case. A 10-year planning by the proposed method was run in about 4 minutes.

Since the proposed method is based on the analytic function, it is believed that the more efficient and accurate investment planning could have been achieved.

5. Conclusions

As a power system planning tool, this paper has presented new, efficient and accurate analytic methodologies. The scope of this work can be devided into two phases;

Phase I : Optimal operation

Phase II : Optimal Long-term Generation Expansion Planning.

Major contributions to the long-term generation planning may be summerized as follows:

Phase I:

1) the analytic production costing for the pure thermal system (Park's Model) is extended to include the pumped-storage plant operation. Based on the unified concept of "Supplied Demand" which takes the lesser one between random load and random plant capability, the formula of the expected supplied demand including pumping case is derived. Since this formula is analytic, the efficiency of computation has greatly been enhanced than other methods, for example, used in WASP and MNI.

2) Instead of computing the reliability as the constraint which is usually applied in power system calculations, this paper manipulates the reliability as the variable which can be optimized. For this purpose, the analytic supply-storage cost is included in the simulation. Combining this with the operation cost, an efficient cost function can be defined and the system's reliability can easily be optimized with this cost function.

3) With the cost function defined above, the efficient and accurate optimal pumped-storage plant operation has been achieved using the defined pumping and peak-shaving levels.

Phase II:

4) Based on the analytic cost function, the efficient optimal long-term generation expansion planning model is newly proposed using the maximum principle.

5) The maximum principle is solved by the gradient search due to its simplicity. Every iteration is treated in the form of the mathematical programming such that all controls from the initial to the terminal time are manipulated simultaneously.

6) The major calculation in the proposed model involves the marginal capacity cost in operation. This marginal cost information is obtained from the operation model, and therefore the focusing key of the problem lies on the efficient simulation of the optimal operation. This could have been achieved by the proposed analytic cost function.

7) The applicability of the model has fully been verified and results are shown in Table 3 and 4, comparing obtained results with the MNI's. Tables show that the proposed method is favorably comparable with the existing package MNI in the accuracy and efficiency.

Further research works remain, however, on topics such as the inclusion of unit retirement, the more efficient convergence acceleration, the better horizen year selection, etc.

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