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MULTIPLE CRITERIA DECISION MAKING FOR POWER GENERATION INVESTMENT PLANNING UNDER RESTRICTIONS OF AGGREGATE EMISSION CONTROL

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Abstract: This article addresses the economic decision of generating investment planning in order to determine the cost effectiveness of environmental options. The approach of linear programming (LP) with multiple criteria decision making is deployed in analyzing available options to formulate a model in compliance with the recent environmental trends of aggregate emission control from a long-term perspective. An LP model is developed to find the best solution and to decide suitable environmental options. The use of the multiple objective approach is to determine the cost interactions between capital limitations and emission quantities from a long-term cost-effective viewpoint. Each environmental option is first graphed to analyze its effects through a load duration curve and then all the options are mathematically formulated in a cost minimization model followed by model implementation. The implementation is designed as several scenarios to survey the parameter variations of energy production and escalation factors. The implementation results demonstrate that the use of both LP and multiple objective models could help utility planners easily explain the theoretical rigor not found in simpler decision models.

Keywords: Linear programming, multiple criteria decision, cost effectiveness, environmental options.

1. INTRODUCTION

A utility decision planner needs to know how to deal with the environmental issues that influence cost effectiveness. The role of decision models in resource allocation often lies in providing a sound process rather than the best decision per se

[1]. The literature in the area of multiple criteria decision analysis reads like a litany of methods and models, the choice of which can be confusing.

Multiple criteria programming methods are widely used for comparing alternatives in utility planning when there are multiple objectives. Chai and Ho [1] presented a model to describe the application of multiple criteria decision models in allocating resources for electric utilities characterized by a large number of projects competing for limited funding, the presence of fuzzy criteria, and the available data beginning naturally ordinal. Evans, Morin, and Mosjowitz [4] developed a multiobjective energy generation model encompassing multiple, often conflicting, objectives, uncertainties, and risks for measuring an electric utility's objectives and dynamic programming to optimize the choice of an expansion policy.

Most planners and interest representatives applied direct weight assessment, trade-off weight assessment, additive value functions, and goal programming while implementing multiple objective models and concluded that they could provide insight and confidence in decision making. However, Hobbs and Meier [7] criticized these methods as biased and no single method emerged as best.

The problem of evaluating environmental options arises in two different considerations in electric utilities. In the first consideration, a specific plant is ready to build but the best option for complying with environmental regulations has yet to be determined. The building of such a power generation plant with pollutants requires the evaluation of different types of environmental options based on technical, social, financial, and cost factors. The second consideration deals with the extension of feasibility of resource allocation at the corporate level for projects regarding funding and emission controls [1].

Power system planning encounters problems regarding the interrelationship of capital budgeting and financing with international circumstances. As investments in power generation facilities are characterized as capital intensive undertakings and thus distinguished by longevity during planning, financial analysis has been widely included to optimize power generation planning since the 1960s. Starting in the 1970s, planning shifted and was confined to economizing dispatch, attempting to save fuel due to OPEC's oil embargo. However, interest issues have changed again to comply with the wave of environmental protection since the mid-1980s. The future planning of power systems faces a new era in searching for cost-effective options to meet stringent environmental provisions [2, 14]. However, results from current studies regarding the economic importance of conventional energy generation and the potential for significant savings remain unclear and require investigation.

An environmental option may remain important for years because its effects are closely related to either capital or variable cost disbursements. Effects, for example, from installing a set of power generation or environmental equipment may last for many decades. To measure effects against costs or benefits, interest rates are used to represent the time value of money through discounted cash flow approaches. A typical approach in planning capital investments related to a power generation facility was to treat the problem as a static situation, where cost or revenue relationships remained fixed over time. Since cost components may influence the decision between investment costs and benefits, a time factor requiring more explicit treatment was recommended [3]. For instance, a power generation installation is greatly influenced by the interaction between current capital expenditures and long term fuel costs. Consequently, multi-period planning is preferable when scheduling the generation mix for appropriate generation type and optimal years in addition to generation capacity.

Ratified in December 1997, the Framework Convention on Climate Change (FCCC) became the first protocol in the world to deal with the greenhouse effect. Several issues were on the agenda, but the central issue was carbon dioxide (CO_2), a by-product of fossil combustion [15]. Consequently, utilities having a high ratio of power generation mix at thermal plants face a challenge in abating their emission levels. The full range of options available to control emissions includes emission constraints in the power system operation, fuel switching/mixing, energy conservation, demand control, purchase/sale emission allowance, installation of power plant emission control technologies, and efficiency improvements. However, each of these options faces problems in either economic feasibility or social acceptance and needs further investigation.

The above environmental options available for utilities are in fact limited because some of them are unrealistic. For instance, as a practical matter most utilities may consider either the installation of equipment to remove CO_2 or switch to little or no CO_2 pollution such as oil or nuclear power plants. The installation of removal equipment requires large capital investments, long lead times for construction, and lowers generation operation efficiency. Fuel switching from high to low emission content fuels may or may not involve large capital investments depending on the unit pattern and fuel type but usually having a higher fuel cost. The capital cost of fuel switching can vary widely from utility to utility as well as from plant to plant.

This study constructs an optimization model to investigate a set of options for a utility complying with environmental regulations to discover:

1. How emission regulations influence production costs
2. Which options are cost-effective
3. How to schedule generation units to power systems under emission and demand restrictions.

2. POWER SYSTEM PLANNING

Power system planning deals with the long-term aspects of determining how a utility is going to meet power needs given cost and reliability constraints. Generation involves determining the number, type, and schedule of power generating unit additions for future use. The cost of implementing a given power generation plan is usually the sum of the fixed and variable cost for the units adjusted for demand variation.

Utilities also employ the capacity factor associated with each generation unit increment to determine the total cost of the generation plan. This requires load forecast information on a load duration curve (LDC). Typically, a mix of peaking, intermediate peaking, and base load units represents corresponding low, moderate, and high capacity factors.

Units with low fixed and high variable costs, such as combustion turbines, are cost-effective for peaking duty. Meanwhile, units with relatively high fixed costs and low variable costs are suitable for base load operations. The intermediate peaking units are in the transition zone between the two cases described above.

3. PROJECTING POWER GENERATION UNITS

Given an array of new power plants with differing capital and operating costs and the objective of meeting demand for electricity at minimum cost, a break-even analysis approach can decide the optimal plant mix in the target year.

Figure 1 portrays a graphical procedure for determining the static optimum mix of power plant types, with three types of plants, A, B, and C. The bottom portion of Figure 1 plots the annual costs for each of the three types divided into fixed costs (intercept) and costs which vary with operation length (slope). H_i and H_j indicate the duration of the operation for plants that can produce cheaper output than others. For instance, beyond H_j, plant type A is more economical than plant B or C.

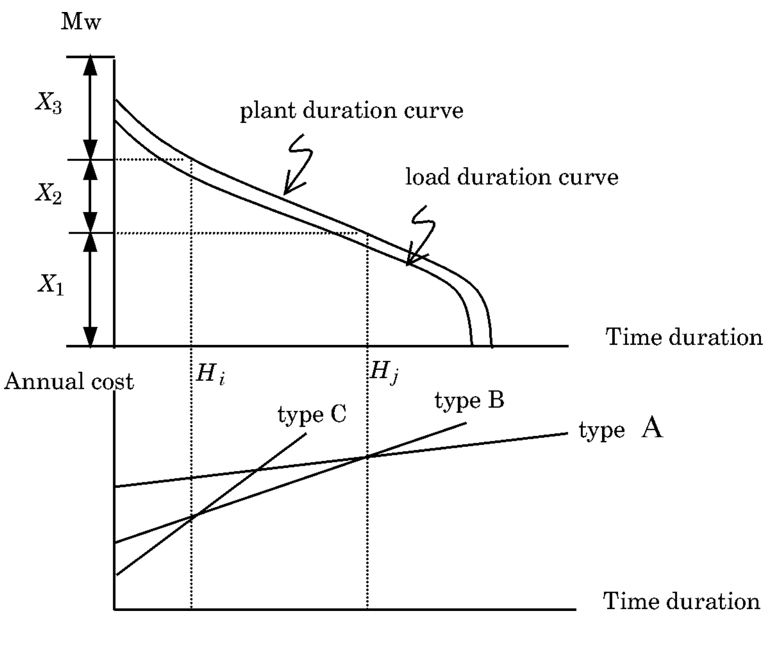

Figure 1: Static optimum plant mix

H_i and H_j can be projected onto the plant duration curve. The plant duration curve is a cumulative distribution of plant production and, as such, may differ considerably from the load duration curve because of forced outage. The need for a specified reserve margin must be considered when calculating the required percentage of peaking plants but this is not considered here.

Levin and Zahavi [10], Levin et al. [11], Levin et al., [12], and Sherali [16] have derived and proven the optimal mix algorithm. The difference between this analysis and those above is that those analyze the break-even figure first and then use the break-even point to decide the supply portion on the LCD. This means that they determine the supply side first and then the demand side. However, the capacity expansion of a power system may be based on the demand side.

If the horizontal axis represents percentage of operation instead of time duration (Fig. 2), plant type A becomes a base load plant. Meanwhile, plant type B supplies the intermediate load less frequently than plant type A. Plant type B typically operates 70% of the time. Furthermore, plant type C supplies for the peaking load only and typically operates 15% of the time or less. Finally, there are other types of plants called type D which are not included in this diagram because these plants represent proven technologies that are not currently economical. Usually, plant types such as solar generation are considered as backstop technologies [6] and will become economic and available when the costs of other plant types increase or when solar generation costs decrease sufficiently. The lower envelope of these curves give the minimum cost function, as Fig. 2 shows.

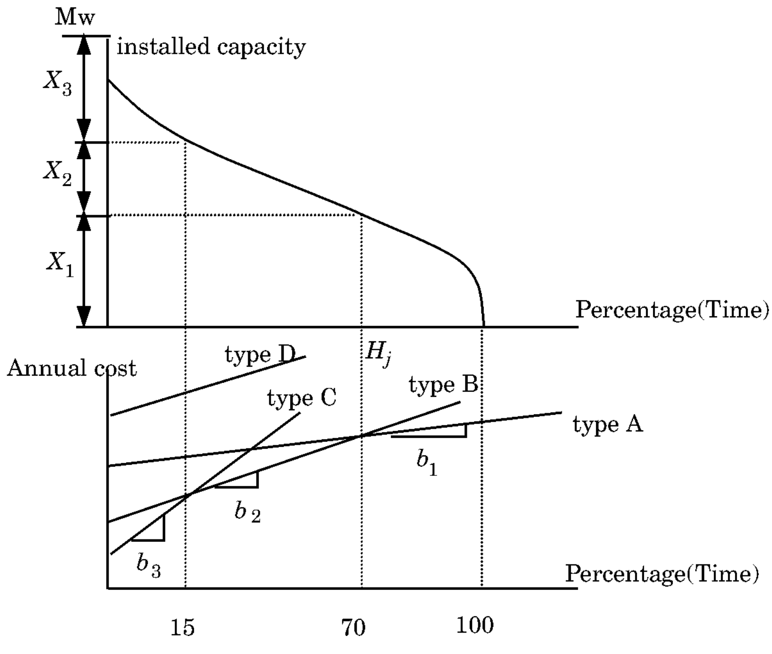

Figure 2: Static optimum plant mix represented as a percentage

Because the operating and capital investment costs for the various units are inversely related, as the bottom of Fig. 2 indicates, the minimum cost function is a piecewise concave function formed like a polygon. Plant type C is not economical if it operates more than 15% of the total time. Plant type B is economical only if it operates more than 15% and less than 70% of the time, and type A is economical only if it operates over 70% of the time. Therefore, the optimum minimum capacity to be installed for each plant type is obtained by projecting the break-even points onto the LDC. x_1, x_2, and x_3 in the upper portion indicate these minimum capacities for types A, B, and C respectively.

For any load level L, the abscissa proves the duration for which the load exceeds L. Assume N candidate plant types, with plant i having a unit annualized capital cost of $c_i\,(\$Mw)$, and a unit operating cost of $b_i\,(\$Mw)$, $i = 1,\ldots,N$.

The loading procedure called **merit order** loading arranges generating units as:

$$c_1 > c_2 > \cdots > c_N > 0 \quad \text{and} \quad 0 < b_1 < b_2 < \cdots < b_N \tag{1}$$

If $b_i < b_j$ and $c_i < c_j$, generating unit j is inferior to unit i, and would be discarded from the mix of generating units to supply the demand.

Let H_{ij} denote the point on the time axis at which the total variable and fixed costs for units i and j $(j < i)$ are equal, then the break-even point is:

$$H_{ij} = \frac{c_j - c_i}{b_i - b_j} \tag{2}$$

The problem of selecting an optimizing plant mix to minimize total capital and operating costs is determined by a straightforward graphical procedure. Let $TC_i(h)$ be the total annual cost of owning and operating one megawatt of capacity i for a period of h. Then,

$$TC_i(h) = c_i + b_i h \tag{3}$$

Capacity type i is the best choice for load level L during time period h if and only if $TC_i(h) \le TC_j(h)$ for all j not equal to i. The implementation of the decision rule in this relationship can be expressed by a break-even analysis. In Figure 2, $N = 3$, and the respective optimal capacities x_i^*, $i = 1,2,3$ are determined by projecting the break-even points for the total cost curves onto the LDC. The total annual capital cost associated with this choice is

$$\text{Total annual capital cost} = c_1 x_1^* + c_2 x_2^* + c_3 x_3^* \tag{4}$$

$$\text{Total annual operating costs} = b_1 x_1^* + b_2 x_2^* + b_3 x_3^* \tag{5}$$

The total annual operating cost similarly provides the respective operating cost times the energy served by each equipment type, where the energy served equals the area of the corresponding horizontal span as Fig. 2 illustrates.

In a discrete case, however, an approximation of LDC with step functions can help solve the optimum mix problem. Consider a step function, as Fig. 3 indicates, where β_i are the selected mesh points, and d_i are the areas of the corresponding rectangular load segments [13, 15].

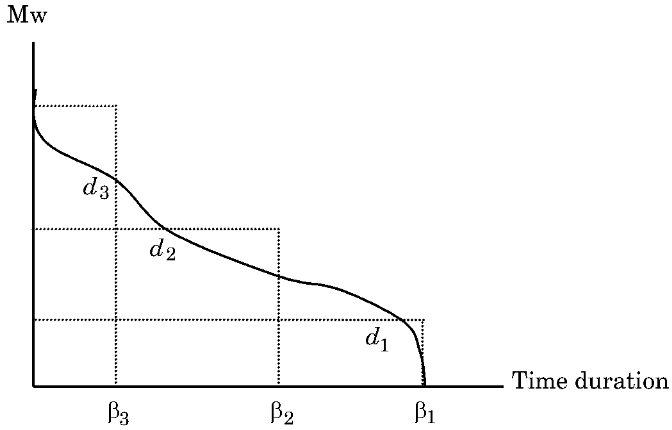

Figure 3: Discrete load curve

Let y_{ij} be the capacity of plant type i allocated to load segment j, $j = 1, 2, \ldots, N$, $N = 3$ in this case.

The LP model can be written as:

$$\begin{aligned}
&\min \sum_{i=1}^{N} c_i x_i + \sum_{i=1}^{N} b_i \left[\sum_{j=1}^{N} \beta_j y_{ij} \right] \\
&\text{s.t.} \\
&\sum_{j=1}^{N} y_{ij} \le x_i, \; i = 1, 2, \ldots, N, \qquad (6) \\
&\beta_j \sum_{i=1}^{N} y_{ij} = d_j, \;\; j = 1, 2, \ldots, N, \\
&x, y \ge 0
\end{aligned}$$

This LP formulation is a typical transportation problem and has two sets of constraints. The first set is related to the capacity constraint. The right-hand side supply parameters are replaced by x_i. The right-hand side for the second set of constraints denoted as d_j / β_j corresponds to the width rather than the area of each load segment j. The corresponding optimal values of y_{ij} must be the optimal solution to a transportation problem with three sources (in this case) having respective supplies x_i^*, $i = 1,2,3$ and three destinations indexed by $j = 1,2,3$, having respective demands d_j / β_j for $j = 1,2,3$ if x_i^* is the optimal solution to this LP formulation. Figure 3 represents the graphical solution to this problem with the LDC illustrated there replaced by the discrete LDC. Given x_i^*, $i = 1,2,3$, the corresponding quantities $\{y_{ij}^*\}$, $i = 1,2,3$ and $j = 1,2,3$ are determined by the merit order rule described in the previous section.

4. EFFECT OF ENVIRONMENTAL REGULATIONS

A utility has at least four options to reduce the effects of FCCC provisions:

1. Switching fuels from high to low emission contents.
2. Installing removal equipment at polluted plants.
3. Purchasing allowable emission credits from emission markets.
4. Improving generation efficiency to cut emission.

Among these assessable options, the first option is usually related to national energy policy, site appropriateness, and source allocations, which may not be controlled by any utility. The second option, installing removal equipment at polluted plants, may become a common approach employed by utilities. The performance data given in current articles differ not only in specific design features and removal options, but also in the degree of design analyses and the use of different assumptions for boundary conditions [5]. Moreover, many environmental controls must be added as separate facilities, and some of the plant's power must be used to operate these controls, raising the cost and complexity of the power plant and reducing its efficiency. As such, environmental controls account for more than 30% of power plant costs. A study estimated that using current technology for CO_2 capture from flue gas derived from conventional pulverized coal fired power stations increases the nameplate capacity and produces a consequential increase of 50% in electricity prices [8].

The third alternative, purchasing emission credits, will not affect generation capacity, fixed costs, or variable costs. Although this option is somewhat limited by political and economic factors, such as price, and quantity availability may be full of uncertainty, it does provide a possible way to make alternations while thinking and searching for optimal solutions.

Since emission credits are tradable, each utility faces a decision regarding how much of their emissions to clean up and how many credits to hold onto. The option will depend upon the relative cost of technological options and credits. Finally, the fourth option indicates progress in technology, which can currently not be expected on any certain schedule.

The prospects of an expected increase in fuel costs and a slight increase in capital costs are critical when a utility is considering switching fuels. Since low emission fuels are nonrenewable and limited sources of energy worldwide, this option is highly sensitive to expected fuel prices. Figure 4 depicts the effect graphically in which the intercept and slope are changed. The capability of energy supply increases as combustion efficiency improves.

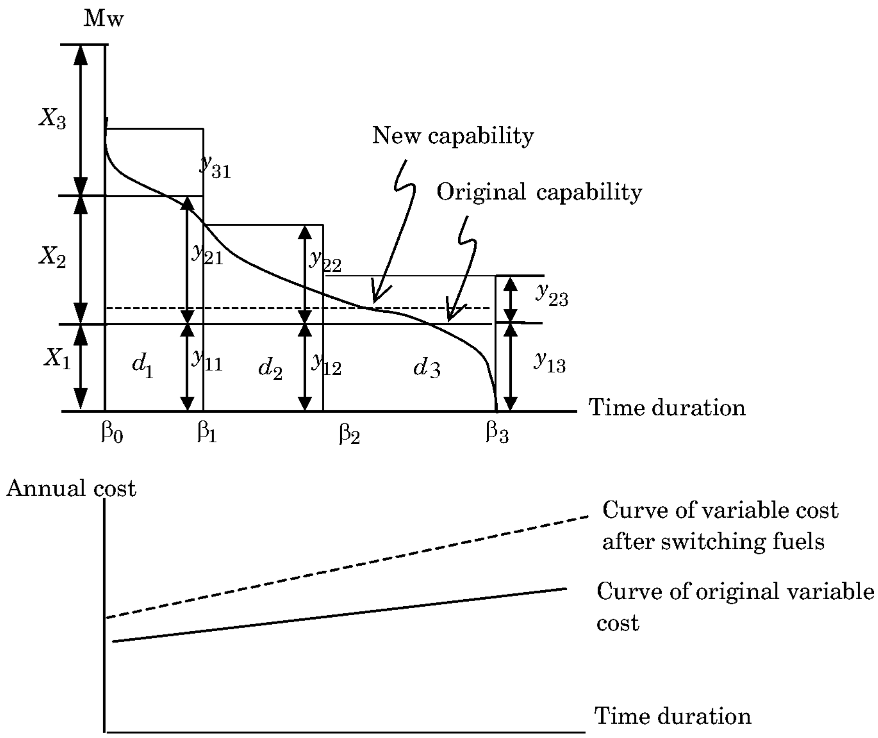

Figure 4: The effect of switching fuels

The second option is to install removal equipment in power generation plants. The installation of removal equipment, as Fig. 5 shows, will not only increase the required capital cost investments but will also decrease production efficiency due to increased internal power requirements and the required capacity derating. Since the power system becomes more complex when removal equipment is retrofitted, reliability reduces and operating and maintenance costs increase. However, fuel price increases are expected to be lower since more abundant high carbon dioxide coal can be purchased.

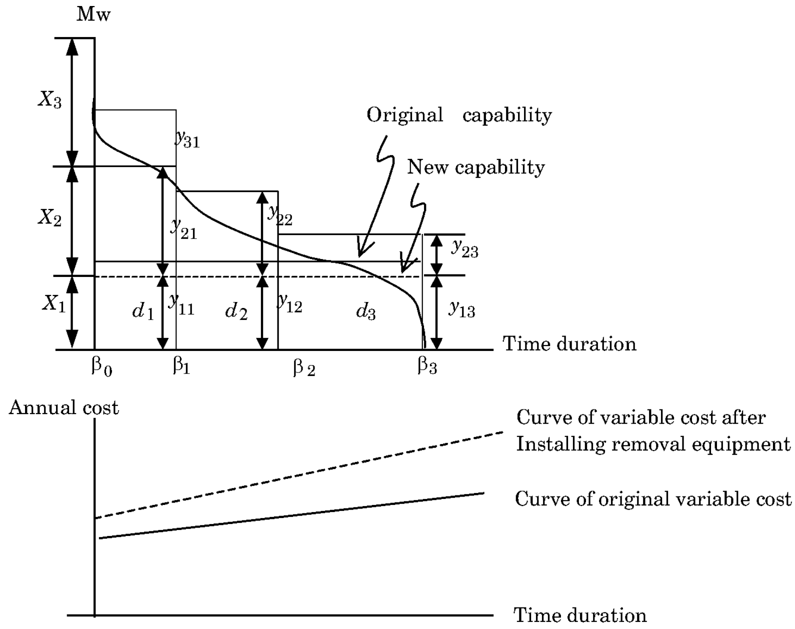

Figure 5: The effect of installing removal equipment

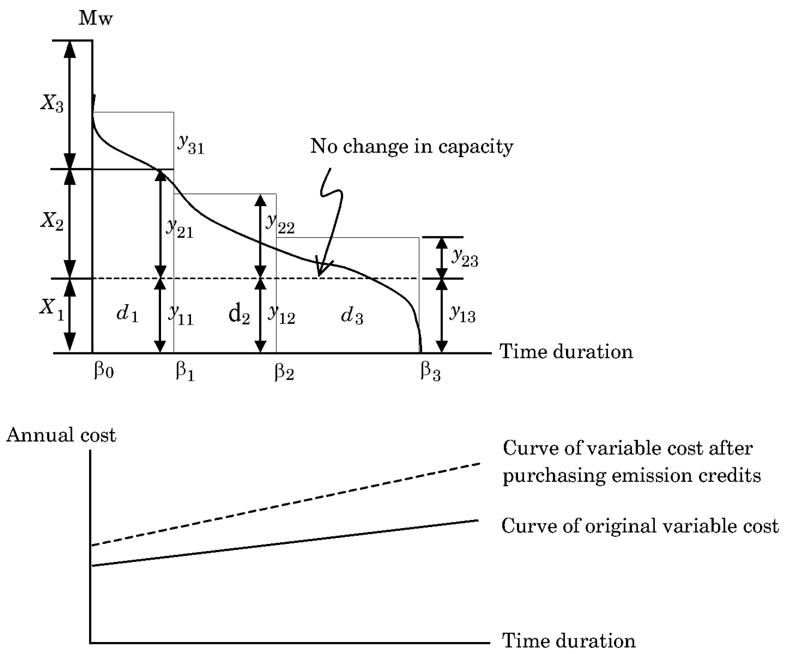

Figure 6: The effect of purchasing emission credits

The third option, purchasing an allowance emission credit, somewhat resembles a carbon tax that must be paid for government permits or permits from other utilities that depend on the emission credit market, which is mostly unpredictable and not dominated by any single utility. Despite the 'emission credit market' being impossible to control, it is possible to compute how much emission credit must be purchased if there is a deficiency of emission allowance exists. Basically, this option changes variable costs only and Fig. 6 reveals its effect, with only the slope being changed.

The final option is similar to the first option regarding capital and variable costs, as Fig. 7 depicts. However, this option is more efficient than the first one and the capital required is proportional to the degree of efficiency.

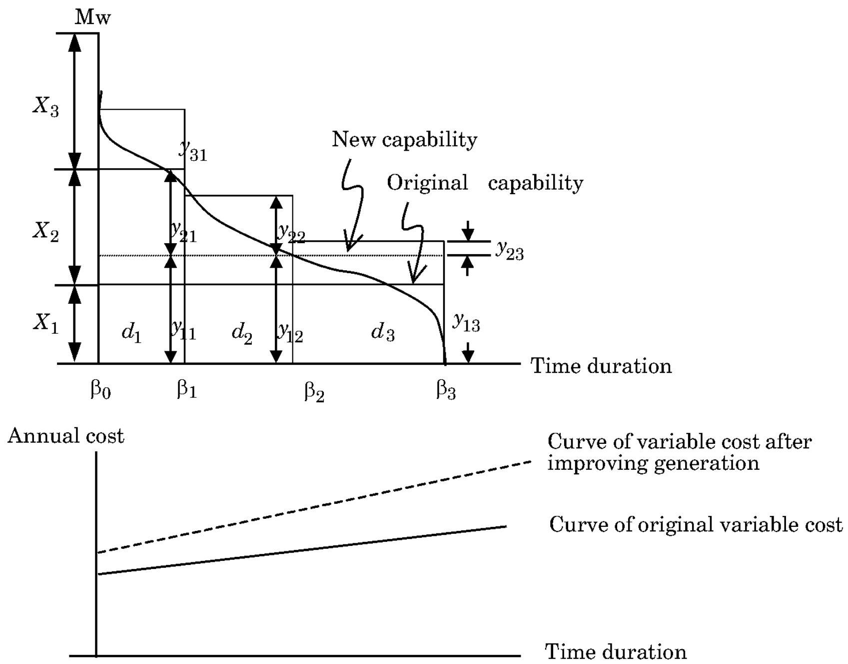

Figure 7: The effect of improving generation efficiency

Table 1 summarizes components for all environmental options.

Table 1: Components of environmental options

Options	Capital costs	Variable costs	Energy supply
1	Slightly increased[a]	High	Slightly increased
2	High	Same or slightly increased[c]	Decreased
3	No	High	No change
4	Medium to high[b]	High	Increased

a: use for changing combustion equipment. b: depending on the improvement degree. c: resulting from the removal degree related to O&M costs

5. MODEL FORMULATIONS

Nomenclatures:

β_{tj} : the selected mesh point of time duration t for plant j, hours.

a : escalation factor of emission credit, %.

b_k : initial variable costs for environmental option k, $/kWh.

B_t : emission savings in year t, Kg.

c_k : levelized capital for environmental option k, $/Kw

d_{tj} : load for satisfying the rectangular area between $\beta_{t,\,j-1}$ and β_{tj}

d_{tj} : $q_{t,\,j-1} * (\beta_{tj} - \beta_{t,\,j-1})$

f_k : escalation factor for c_k , %.

g_k : escalation factor for b_k , %.

i : plant index, $i = 1,\ldots, N$.

I_{ik} : binary variable for plant i.

j : index for interval of time duration, $j = 1,\ldots,W$

k : environmental option index, $k = 1,\ldots, M$

L_t : binary variable to determine the sale of B_t in year t.

p : unit cost of emission credit, $/Kg

Q : allowable emission quantity, Kg/year.

q_{tj} : load demand between β_{tj} and $\beta_{t,\,j-1}$, Kw.

s_k : unit CO_2 emission for option k (Kg/kWh), $k = 1,\ldots, M$

t : planning years, $t = 1,\ldots,Y$.

u_k : capacity variation for environmental option k, %.

x_i : capacity of plant i, kWh.

y_{tij} : allocation of load segment for x_i from β_{tj} to $\beta_{t,\,j-1}$, Kw.

5.1. Formulation of the linear programming model

A linear programming model including the considerations above is firstly organized as follows:

The objective function

$$\min \sum_{t=1}^{Y}\sum_{i=1}^{N}\sum_{k}^{M} c_k(1+f_k)^t x_i I_{ik} + \\ +\sum_{t=1}^{Y}\sum_{i=1}^{N}\left\{\left[\sum_{k=1}^{M} b_k(1+g_k)^t I_{ik}\right]\times\left[\sum_{j=1}^{W} y_{tij}(\beta_{tj}-\beta_{tj-1})\right]\right\} - \sum_{t=1}^{Y} B_t \times L_t \times p(1+a)^t \tag{7}$$

The objective function includes three parts: capital investments, variable costs, and emission sales. The first term is the sum of capital investments related to environmental options, and the second term represents the energy production with regard to variable costs. While implementing environmental option 2 or 4, an emission surplus may exist as a deduction term replacing emission sales in the last term. The terms of $(1+f_k)^t$, $(1+g_k)^t$ and $(1+a)^t$ represent the escalation factors for capital costs, variable costs and selling prices in the specific year t.

Constraints

Capacity

$$y_{tij} \le x_i \times \left[\sum_{k=1}^{M} (1+u_k) * l_{ik} \right], \quad i=1,2,\ldots,N,\ j=1,2,\ldots,W,\ t=1,2,\ldots,Y \tag{8}$$

The load supply must satisfy load segment demand in any given year. However, the load supply from plants may vary in terms of u_k while implementing environmental options as described in the previous section. The values of u_k are:

Option 1: $u_k > 0$.
Option 2: $u_k < 0$.
Option 3: $u_k = 0$.
Option 4: $u_k > 0$.

According to the merit order schedule, load demand must satisfy each load segment in any given year as follows:

$$\sum_{i=1}^{N} y_{tij} = q_{t,\,j-1}, \quad j=1,2,\ldots,W,\ t=1,2,\ldots,Y \tag{9}$$

The capacity of x_i in year t must satisfy the sum of load interval j, y_{tij}, related to $q_{t,\,j-1}$, the load requirement, as follows:

$$\sum_{i=1}^{N} \left\{ x_i \times \left[\sum_{k=1}^{M} (1+u_k) * l_{ik} \right] \right\} \ge q_{t0}, \quad t=1,2,\ldots,Y \tag{10}$$

The energy constraint

$$(\beta_{tj} - \beta_{t,\,j-1}) \times \sum_{i=1}^{N} y_{tij} = d_{tj}, \quad j=1,2,\ldots,W,\ t=1,2,\ldots,Y \tag{11}$$

The operation of power plants i for load allocation j (y_{tij}) in time interval t $(\beta_{tj} - \beta_{t,\,j-1})$ must equal d_{tj}.

The restriction of CO2 emissions

$$\sum_{i=1}^{N}\left[\sum_{j=1}^{W} y_{tij}\times(\beta_{tj}-\beta_{t,\,j-1})\times\left(\sum_{k=1}^{M} I_{ik}\times s_k\right)\right]\le Q+B_{t-1},\quad t=1,\ldots,Y \tag{12}$$

In a specific year t, the sum of CO_2 emissions is calculated by energy production $(y_{tij}*(\beta_{tj}-\beta_{t,\,j-1}))$ multiplied by the unit emission, s_k and should be less than the allowable emission quantity plus the emission savings from the previous year, B_t.

Where,

$$B_0=0$$

$$B_t=\left\{B_{t-1}+Q-\sum_{i=1}^{N}\left[\sum_{j=1}^{W} y_{tij}\times(\beta_{tj}-\beta_{t,\,j-1})\times\left(\sum_{k=1}^{M} I_{ik}\times s_k\right)(1-I_{i3})\right]\right\}\times(1-L_t) \tag{13}$$

for $t=1,\ldots,Y$

Equation (13*)* indicates that the quantity of emission savings in year t, B_t, is determined by the quantity of emission savings in the previous year t, B_{t-1}, plus the allowable emission quantity, Q, and minus the emissions produced in the current year. The term $(1-I_{i3})$ is used to exclude option 3 where $I_{i3}=1$ or $1-I_{i3}=0$ since purchasing more emission allowance than required is uneconomical. The term $(1-L_t)$ indicates that the value of B_t becomes zero if the emission savings are sold in the previous years in terms of $L_t=1$ or $1-L_t=0$. The Appendix proposes the derivation of s_k.

Integer variables

$$\sum_{k=1}^{M} I_{ik}=1,\ \text{for}\ i=1,\ldots,N \tag{14}$$

Equation (14) reveals that only one environmental option may be selected for plant i. The environmental option must be continued until the end of the planning period once the selection is determined.

$$\begin{aligned}&1\ge L_t\ge 0\quad t=1,\ldots,Y\\&L_t\ \text{is binary.}\end{aligned} \tag{15}$$

5.2. Formulation of the multiple objective model

Whether a decision is best is often impossible to validate, but processes can be designed in accordance with the criteria, data, and organization setting. Deviation is introduced into the linear programming model when considering multiple objectives to deal with long-term cost and pollution emissions minimization in a satisfactory solution. A typical pattern of a multiple criteria model is:

$$\begin{aligned} &\min\ Z_k(x) \quad \text{for} \quad k=1,\dots,p \\ &\text{s.t.}\ \ a_{ij}x_i \le b_i \quad i=1,\dots,m,\ \ j=1,\dots,n \\ &\qquad x_i \ge 0 \end{aligned} \tag{16}$$

If T_k is the setting value of objective function $Z_k(x)$, then,

$$\begin{aligned} &\min\ \sum_{k=1}^{p} \left| Z_k(x) - T_k \right| \\ &\text{s.t.}\ \ a_{ij}x_i \le b_i \ \ \text{for} \ \ i=1,\dots,m,\ j=1,\dots,n \\ &\qquad x_i \ge 0 \end{aligned} \tag{17}$$

A negative deviation variable (d_k^-) or positive deviation variable (d_k^+) is imposed on the objective function $Z_k(x)$ to indicate less, greater, or equal to zero situations such that $Z_k(x) = T_k$. While the deviation is positive, d_k^+ exists; otherwise d_k^- exists. Both may be zero if $Z_k(x)$ is exactly equal to T_k. The objective function is then formulated as a minimization pattern to search for the deviation between $Z_k(x)$ and T_k as follows:

$$\begin{aligned} &\min\ \sum_{k=1}^{p} (d_k^+ + d_k^-) \\ &\text{s.t.}\ \ a_{ij}x_i \le b_i \quad \text{for} \ \ i=1..m,\ j=1..n \\ &\qquad x_i \ge 0 \\ &\qquad Z_k(x) + d_k^- - d_k^+ = T_k \quad \text{for} \ \ k=1,\dots,p \\ &\qquad d_k^+, d_k^- \ge 0 \end{aligned} \tag{18}$$

The objective function of the linear programming model above can be divided into two parts: minimization of long-term cost components and minimization of emissions. The minimization of long-term cost components consists of two parts: capital investments and variable costs. The first term is the sum of capital investments related to environmental options. The second term represents energy production with regard to variable costs. The terms of $(1+f_k)^t$ and $(1+g_k)^t$ represent the escalation factors for capital costs and variable costs in the specific year t. The model that incorporates the two objective functions is:

$$\min \sum_{t=1}^{Y}\sum_{i=1}^{N}\sum_{k}^{M} c_k(1+f_k)^t x_i I_{ik} + \sum_{t=1}^{Y}\sum_{i=1}^{N}\left\{\left[\sum_{k=1}^{M} b_k(1+g_k)^t I_{ik}\right]\times\left[\sum_{j=1}^{W}(\beta_{tj}-\beta_{tj-1})y_{tij}\right]\right\}$$

$$\min \sum_{t=1}^{Y}\sum_{i=1}^{N}\left[\sum_{j=1}^{W} y_{tij}\times(\beta_{tj}-\beta_{t,\,j-1})\times\left(\sum_{k=1}^{M} I_{ik}\times s_k\right)\right]$$

Subject to:

Capacity limitations

$$y_{tij} \le x_i \times\left[\sum_{k=1}^{M}(1+u_k)*I_{ik}\right],\quad i=1,2,\ldots,N,\ j=1,2,\ldots,W,\ t=1,2,\ldots,Y$$

$$\sum_{i=1}^{N} y_{tij} = q_{t,\,j-1},\quad j=1,2,\ldots,W,\ t=1,2,\ldots,Y$$

$$\sum_{i=1}^{N}\left\{x_i\times\left[\sum_{k=1}^{M}(1+u_k)*I_{ik}\right]\right\}\ge q_{t0},\quad t=1,2,\ldots,Y$$

Energy output limitations

$$(\beta_{tj}-\beta_{t,\,j-1})\times\sum_{i=1}^{N} y_{tij} = d_{tj},\quad j=1,2,\ldots,W,\ t=1,2,\ldots,Y$$

Restriction of CO_2 emissions

$$\sum_{i=1}^{N}\left[\ \sum_{j=1}^{W} y_{tij}\times(\beta_{tj}-\beta_{t,\,j-1})\times\left(\sum_{k=1}^{M} I_{ik}\times s_k\right)\right]\le Q\quad t=1..Y$$

Integer variable

$$\sum_{k=1}^{M} I_{ik}=1\ ,\ \text{for } i=1..N$$

When introducing deviation variables into the model, the model formulation becomes:

The objective function:

$$\min \sum_{k=1}^{2}(d_k^{+}+d_k^{-})$$

Constraints:

$$y_{tij} \le x_i \times\left[\sum_{k=1}^{M}(1+u_k)*I_{ik}\right],\quad i=1,2,\ldots,N,\ j=1,2,\ldots,W,\ t=1,2,\ldots,Y$$

$$(\beta_{tj}-\beta_{t,\,j-1})\times\sum_{i=1}^{N} y_{tij} = d_{tj},\quad j=1,2,\ldots,W,\ t=1,2,\ldots,Y$$

$$\sum_{i=1}^{N}\left\{x_i \times \left[\sum_{k=1}^{M}(1+u_k) * I_{ik}\right]\right\} \geq q_{t0}, \quad t=1,2,...,Y$$

$$\sum_{i=1}^{N}\left[\sum_{j=1}^{W} y_{tij} \times (\beta_{tj}-\beta_{t,\,j-1}) \times \left(\sum_{k=1}^{M} I_{ik} \times s_k\right)\right] \leq Q, \quad t=1,...,Y$$

$$\sum_{k=1}^{M} I_{ik}=1, \quad \text{for } i=1,...,N$$

$$\sum_{t=1}^{Y}\sum_{i=1}^{N}\sum_{k}^{M} c_k(1+f_k)^t x_i I_{ik} + \sum_{t=1}^{Y}\sum_{i=1}^{N}\left\{\left[\sum_{k=1}^{M} b_k(1+g_k)^t I_{ik}\right] \times \left[\sum_{j=1}^{W}(\beta_{tj}-\beta_{tj-1}) y_{tij}\right]\right\} -$$

$$-d_1^+ + d_1^- = T_1$$

$$\sum_{t=1}^{Y}\sum_{i=1}^{N}\left[\sum_{j=1}^{W} y_{tij} \times (\beta_{tj}-\beta_{t,\,j-1}) \times \left(\sum_{k=1}^{M} I_{ik} \times s_k\right)\right] - d_2^+ + d_2^- = T_2$$

$$I_{ik} \text{ binary}, \ d_1^+ \cdot d_1^- \cdot d_2^+ \cdot d_2^- \geq 0$$

IMPLEMENTATION

To demonstrate the application of the developed model, this investigation implements two power plants with a planning period of 20 years. Two phases with several scenarios are designed for the model implementation. Phase I demonstrates the linear programming model while Phase II probes the multiple criteria decisions. Table 2 depicts the plant characteristics and initial cost components, and the relevant assumptions are as follows (in US dollar units):

1. The selling price of emissions is $400/Kg with an escalation factor of 7%.
2. The abscissa of time length in LDC is 0, 2,000, 5,500 and 8,760 hours corresponding to a verticality load of 180,000, 155,000, 120,000 and 100,000 Kw respectively.
3. The mitigation target is CO_2.
4. The CO_2 contents are 0.9Kg/kWh for coal fuel and 0.5Kg/kWh for natural gas. The emission standard is set at 0.7Kg/kWh.
5. Options 1 and 4 require mixing coal and natural gas fuels. The mixing ratios are proportionally based on the CO_2 standard. Since the emission standard is set at 0.7Kg/kWh, a ratio of 1:1 is employed. The natural gas fuel costs here are $0.039625/kWh and $0.03375/kWh for both illustrated plants. The variable cost for option 4 is less than option 1 because it operates efficiently.
6. An additional cost of $0.005/kWh as carbon tax is added for option 3.
7. The capital cost recovery factor used for the entire planning period is
8. $F(A/P,10,20)=0.1175$.

Table 2: The plant characteristics and initial cost components

Factors \ Plants			#1 (X_1)	#2 (X_2)
Capacity (Mw)			100	130
Construction cost ($/Kw)			1070	980
Environmental options	1	Fixed cost ($/Kw)	70 (6%)	70(6%)
		Variable cost ($/kWh)	0.03686 (5%)	0.03139 (5%)
		Variation of capacity (Mw)	105 (+5%)	136.5 (+5%)
	2	Fixed cost ($/Kw)	250 (6%)	250 (6%)
		Variable cost ($/Kw)	0.03410(7%)	0.02903 (7%)
		Variation of capacity (Mw)	80 (-20%)	104 (20%)
	3	Fixed cost ($/Kw)	0	0
		Variable cost ($/Kw)	0.03910 (7.5%)	0.0403(7.5%)
		Variation of capacity (Mw)	100 (± 0%)	130 (± 0%)
	4	Fixed cost ($/Kw)	300	300
		Variable cost ($/Kw)	0.03600	0.03120
		Variation of capacity (Mw)	115 (+15%)	149.5 (+15%)

The percentages in parentheses are escalation factors.

Phase I:

The model implementation was initially designed as several scenarios to test the variation of parameters as follows:

1. To understand the economic changes in the planning period, the implementation was conducted yearly, although the designed test length was twenty years.
2. To understand the cost effectiveness among alternatives, the model was tested using an interactive approach for all options within the planning period.

Table 3 displays the results combined with both considerations for the model test. Several meaningful findings are discussed below:

1. The best choice is option 2 for plant #1 and option 1 for plant #2 during the first six years, and then option 2 for both plants from year seven. Consequently, the selection for installing removal equipment may benefit over the long run rather than in the short run.
2. Option 3 is never a solution due to its high variable cost. Meanwhile, option 4 is also never a solution due to its high capital and variable costs. Evidently, a cost gap of 14% may occur if both plants choose option 4 with a cost value of 3.152502E9, compared to the optimal solution value of 2.76454E9.

3. Since the utilization reached full capacity in this scenario and option 4 never became a solution, the efficiency improvement remained uneconomical even given a capacity increase of 15%.
4. The result does not mean that the option 2 is not always the most economical. For instance, a combination of option 1 for plant #1 and option 2 for plant #2 is less economical than option 2 for plant #1 and option 1 for plant #2 in the twenty-year test. However, selling emission savings is somewhat helpful in allowing option 2 to be optimized.

As the results are greatly influenced by parameters such as escalation factors, type of LDC or plant characteristics during implementation, more tests were required. The model was thus further implemented to test the sensitivity of alternatives by changing the vital parameters. The escalation factors of variable costs were switched to 3.5%, 5%, 6%, and 6% for the sequence of four options. Table 4 depicts the results of such a design and relevant observations are made below:

1. Although the best environmental options resemble the combination of the initial result, the entrance time point becomes year eleven for plant #2 due to the escalation factor of variable costs for option 2 declining from 7% to 3.5%.
2. Option 3 remains uneconomical despite its escalation factors declining from 7.5% to 6%. However, the cost gap is narrowed in all test runs.
3. Option 4 is still unable to enter the solution since its escalation remains the same.

In the previous two scenarios, operating hours are assumed to be highly pertinent to energy production. This would never happen in the real world since maintenance requirements, adjustments for economic dispatch related to electricity demand patterns, and for reliability are unavoidable. Hence, the design of low degree operation is demonstrated. The abscissa of time length in LDC is changed to 0, 2,000, 4,500 and 6,500 hours corresponding to load in verticality of 180,000, 155,000, 120,000 and 100,000 Kws respectively. Table 5 depicts the implemented results and some significant findings are listed below:

1. A combination of options 2 and 3 was the solution in the first two years, but soon changed to option 2 for plant #1 and option 1 for plant #2 from years three to eighteen and then to option 2 for both plants. This result indicates that the solution is highly influenced by energy demand. High energy demand benefits the option of installing removal equipment because its capital cost may be recovered and its low variable cost could be an advantage in the long run.
2. As energy demand declined significantly, the optimal combination of option 1 for both plants occurred in year nineteen, later than in the previous two scenarios, i.e. years seven and twelve. This result confirms that an option may not replace a combinatory option.
3. The pattern of LDC will influence the options selected. Consequently, a loading scheme of generation mix is needed.

Figures 8-10 portray the cost trends for the above scenarios over the entire planning periods and Tables 4-6 present the initial implementation results. These are found in the appendix.

Phase II:

In this phase, all data and assumptions are the same as Phase I except:

1. The escalation factor of capital investments is 6%.
2. The escalation factors of variable costs are 3.5% for installing removal equipment, 5% for mixing fuels, and 6% for emission allowance and improving efficiency.

In addition, the CO_2 emissions are assumed to be 0.72Kg/kWh for installing removal equipment, 0.71Kg/kWh for mixing fuels, 0.7Kg/kWh for purchasing emission allowance, and 0.715Kg/kWh for improving efficiency. A total of CO_2 emissions is restricted in three situations: 14,000,000,000Kg, 14,200,000,000Kg, and 13,800,000,000Kg. The capital budget is limited in five situations: $2,100,000,000, $2,300,000,000, $2,500,000,000, $2,700,000,000, and $2,900,000,000.

Table 3: The test results of Phase II

CO_2 limits (Kg)	OBJ / Capital limits($)	d_1^+	d_1^-	d_2^+	d_2^-	OBJ	
13,800,000,000	2,100,000,000	412774200	0	25000000	0	437774200	Plant #1: 3 Plant #2: 3
	2,300,000,000	212774200	0	25000000	0	237774200	Plant #1: 3 Plant #2: 3
	2,500,000,000	12774160	0	25000000	0	37774160	Plant #1: 3 Plant #2: 3
	2,700,000,000	0	45784550	126250000	0	172034600	Plant #1: 3 Plant #2: 4
	2,900,000,000	0	245784600	126250000	0	372034600	Plant #1: 3 Plant #2: 4
14,000,000,000	2,100,000,000	253533000	0	22500000	0	276033000	Plant #1: 1 Plant #2: 1
	2,300,000,000	53533000	0	22500000	0	76033080	Plant #1: 1 Plant #2: 1
	2,500,000,000	612545	0	0	40000000	40612540	Plant #1: 3 Plant #2: 2
	2,700,000,000	0	45784550	0	73750000	119534600	Plant #1: 3 Plant #2: 4
	2,900,000,000	0	168657000	121250000	0	289907000	Plant #1: 4 Plant #2: 4
14,200,000,000	2,100,000,000	153543800	0	20000000	0	173543800	Plant #1: 2 Plant #2: 2
	2,300,000,000	0	46456180	20000000	0	66456180	Plant #1: 2 Plant #2: 2
	2,500,000,000	0	45158940	0	26750000	71908940	Plant #1: 2 Plant #2: 4
	2,700,000,000	31343020	0	0	78750000	110093000	Plant #1: 4 Plant #2: 4
	2,900,000,000	0	168657000	0	78750000	247407000	Plant #1: 4 Plant #2: 4

Table 3 depicts the results for the model test and several meaningful findings are discussed below:

1. The results have provided a good solution to differentiate the cost disbursements in the environmental options and emission control variations. The cost trend could be depicted through different scenario designs, which are useful for strategic planning.
2. The objective function value is the interaction between capital and CO_2 emission limitations. For instance, the stricter the CO_2 emissions, the higher the objective function values. When the capital budget restricts at 2,100,000,000, the objective function values increase from 173,543,800 to 437,774,200 respective to the total CO_2 emissions of 14,200,000,000 and 13,800,000,000, resulting from the deviations from 153,543,800 to 412,774,200 for cost disbursements and from 20,000,000 to 25,000,000 for CO_2 emissions.
3. The option of installing removal equipment (option 2) is preferable when the limit of CO_2 emissions gets stricter. It was not selected as an environmental option when the total CO_2 emissions were under 14,000,000,000 Kg. In contrast, the option of purchasing emission credits is preferable at a low degree of CO_2 emissions.
4. A low degree of CO_2 emissions and capital budgeting would induce a positive deviation of CO_2 emissions. This is because the option of purchasing emission credits without capital investments is economical. However, options for heavy capital investments are selected at a high degree of CO_2 emissions resulting in negative deviations.
5. A cost trend can be observed from the interaction of long-term cost components and emission quantities represented by deviations. The linear programming model provides the best decision for specific environmental options while these deviations give the substantial solutions of possible effects from emission control and capital limitation.

6. CONCLUDING REMARKS

Linear and multiple objective programming can be used in conjunction, but with decomposition the LP models provide the best solution while the other handles practical changes. This article has proved their use in power generation planning.

The cost-effective options for individual plants or units are determined by the interactions of capital investments, LDC pattern, long-term cost expectations for fuels, capacity utilization factors, and plant or unit characteristics. These in turn depend on the compliance costs of dispatching plants as they are part of the utility's overall power supply system as demand grows. The CO_2 compliance will significantly influence the production costs of electric utility plants and overall systems, as operational changes and capital investments are adopted [9].

Methodology used to formulate the model provides an awareness of the importance of decision making in practice. At present few studies involve linear and multiple objective programming together and present their interactions from different viewpoints. Consequently, this study recommends further investigations where utilities face different situations while implementing the proposed model.

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APPENDIX: CALCULATION OF UNIT EMISSION

Theoretically, heat rate represented by kcal/kg can be defined as the full burning of a unit weight of fuel. 1kcal is the heat required to increase 1Nº (from 14.5 Nº to 15.5 Nº) and

$$1\,\text{kwh} = 860\,\text{kcal} \tag{19}$$

The content of heat rate differs from types of fuels in which coal, oil, and natural gas are in an average of 6,600 kcal/kg, 10,400 kcal/kg, and 10,000 kcal/kg respectively.

Where $E_i^T = y_{tij}(\beta_{tj} - \beta_{t,\,j-1})$, then the annual relationship of fuel consumption, heat rate, and generating electricity symbolized by the energy production for a specific plant i is:

$$E_i^T = \frac{f_i^T \times h_i^T}{F} \tag{20}$$

or

$$E_i^T \times F = f_i^T \times h_i^T \tag{21}$$

where,

$E_i^T =$ the theoretical energy production for plant i, kWh/year

$f_i^T =$ the theoretical fuel consumption for plant i, kg/year

$h_i^T =$ the heat rate for plant j, kcal/kg

$F =$ the conversion factor, 860kcal/kWh

The actual energy production quantity affected by equipment design, power generation structure, and operating efficiency is less than the theoretical energy production. Define ρ_i as the plant efficiency, then:

$$\rho_i = \frac{E_i^A}{E_i^T} \tag{22}$$

where,

$E_i^A =$ the actual energy production for plant i, kWh/year

Then,

$$E_i^T = \frac{E_i^A}{\rho_i} \tag{23}$$

Usually, the value of ρ is between 0.35 and 0.40 for traditional coal plants. Meanwhile, from the cost point of view, ρ improves in relation to facility factors in which an initial cost is weighed against a subsequent reduction in expected energy costs [17]. While burning a coal thermal plant, CO_2 is emitted and can be calculated as follows:

$$\mathrm{CO2}_{\mathrm{coal}} = f_{j,\mathrm{coal}}^{T} \times h_{j,\mathrm{coal}}^{T} \times 44/12/10^{3} \times 4.1868\,\mathrm{J/cal} \times \eta_{\mathrm{coal}} \times \varepsilon \tag{24}$$

where,

$\eta_{\mathrm{coal}} =$ carbon emission rate, 25.8 kgC/GJ

$\varepsilon =$ carbon-oxygenated ratio, 0.98

The right-hand side terms in Equation (21) are the same as the first two terms of the right-hand side in Equation (24). This implies that the CO_2 emissions are proportional to energy production.

CO_2 emissions can be reduced in two ways: enhancing the generation efficiency of $E_i^T \times F = f_i^T \times h_i^T$ or reducing the value of η_{coal}.

1. Enhancing the generation efficiency of $E_i^T \times F = f_i^T \times h_i^T$

Substituting $f_{j,\mathrm{coal}}^{T} \times h_{j,\mathrm{coal}}^{T}$ by Equation (20)

$$\mathrm{CO2}_{\mathrm{coal}} = \frac{E_i^A}{\rho_i} \times 44/12/10^{3} \times 4.1868\,\mathrm{J/cal} \times \eta_{\mathrm{coal}} \times \varepsilon$$

Let s_k be the unit emission, then

$$s_k = \frac{\mathrm{CO2}_{\mathrm{coal}}}{E_i^T} = \frac{E_i^A \times F}{\rho_i E_i^T} \times 44/12/10^{3} \times 4.1868\,\mathrm{J/cal} \times \eta_{\mathrm{coal}} \times \varepsilon$$

Therefore, s_k can be reduced if ρ_i is enhanced. Since a mix of fuels is required while improving generation efficiency, the value of η_{coal} can be reduced through fuel mixing as follows.

2. Reducing the values of η_{coal}.

This means that besides carbon emission rate (η_{coal}), other terms in Equation (24) are viewed as constant. η_{coal} is vital for reducing total CO_2 emission if other terms in Equation (24) are fixed.

While burning a natural gas plant, the calculation of CO_2 emissions is:

$$\mathrm{CO2}_{\mathrm{gas}} = f_g^{T} \times h_g^{T} \times 44/12/10^{3} \times 4.1868\,\mathrm{J/cal} \times \eta_g \times \varepsilon_g \tag{25}$$

where,

f_g^T = fuel consumption for natural gas, $10^6 m^3$/year

η_g = carbon emission rate for natural gas, 15.3kgC/GJ

ε_g = carbon-oxygenated ratio, 0.995

The switching or mixing effect for calculating total CO_2 emissions can be represented as follows:

$$\begin{aligned} CO2 &= w_{coal} Total_{coal} + w_{gas} Total_{gas} \\ &= w_{coal} \times E_{coal}^T \times F \times 44/12/10^3 \times 4.1868\, J/cal \times \eta_{coal} \times \varepsilon_{coal} \\ &+ w_{gas} \times E_{gas}^T \times F \times 44/12/10^3 \times 4.1868\, J/cal \times \eta_{gas} \times \varepsilon_{gas} \end{aligned} \tag{26}$$

where w_{coal}, w_{gas} are fuel mixing ratios for coal and natural gas.

If w_{gas} is equal to 1, coal is totally switched. Meanwhile, coal is the sole fuel if w_{gas} is equal to 0. Therefore, the total and unit CO_2 emissions will decline proportionally with the values of w_{gas} and w_{coal} pertinent to η_{gas} and η_{coal}.

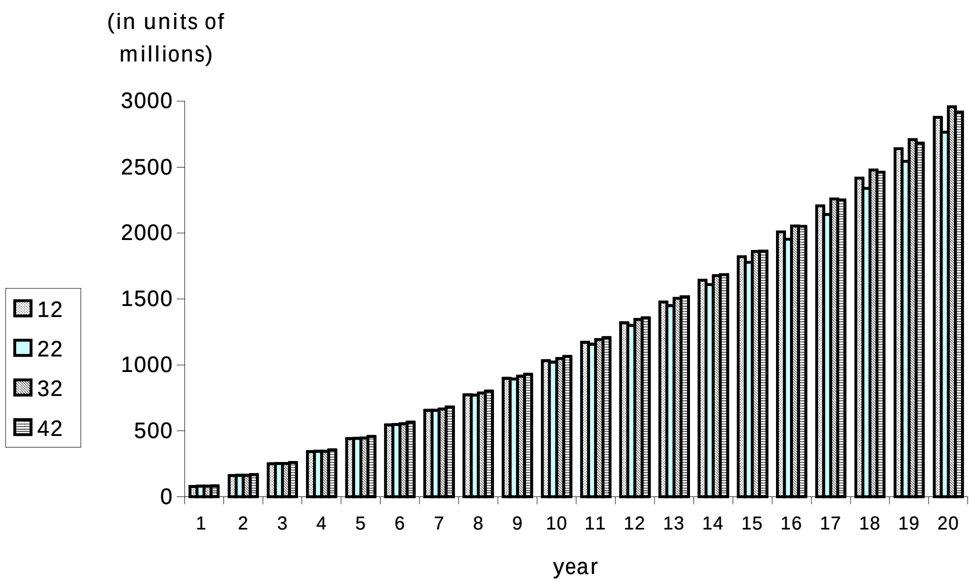

Figure 8: The initial implementation results of the model test

Table 4: The initial implementation results of the model test

year			X_2			
		Options	1	2	3	4
X_1	20	1	0.3149733E+10	0.3118964E+10	0.3185533E+10	0.3226767E+10
		2	0.2876126E+10	0.2764540E+10	0.2957315E+10	0.2918043E+10
		3	0.3285272E+10	0.3238340E+10	0.3330150E+10	0.3355283E+10
		4	0.3061420E+10	0.3062978E+10	0.3079064E+10	0.3152502E+10
	19	1	0.2878720E+10	0.2855751E+10	0.2909318E+10	0.2952491E+10
		2	0.2639529E+10	0.2545475E+10	0.2710459E+10	0.2682870E+10
		3	0.2997279E+10	0.2960092E+10	0.3035943E+10	0.3064964E+10
		4	0.2807267E+10	0.2812731E+10	0.2821731E+10	0.2893210E+10
	18	1	0.2624605E+10	0.2608335E+10	0.2650606E+10	0.2694897E+10
		2	0.2416389E+10	0.2337831E+10	0.2478135E+10	0.2460439E+10
		3	0.2727949E+10	0.2699221E+10	0.2761099E+10	0.2792993E+10
		4	0.2567806E+10	0.2576451E+10	0.2579509E+10	0.2648595E+10
	17	1	0.2386329E+10	0.2375758E+10	0.2408281E+10	0.2452965E+10
		2	0.2205930E+10	0.2141006E+10	0.2259469E+10	0.2250056E+10
		3	0.2476064E+10	0.2454622E+10	0.2504333E+10	0.2538198E+10
		4	0.2342187E+10	0.2353357E+10	0.2351504E+10	0.2417826E+10
	16	1	0.2162901E+10	0.2157122E+10	0.2181299E+10	0.2225737E+10
		2	0.2007423E+10	0.1954434E+10	0.2053639E+10	0.2051065E+10
		3	0.2240485E+10	0.2225264E+10	0.2264447E+10	0.2299483E+10
		4	0.2129606E+10	0.2142710E+10	0.2136876E+10	0.2200119E+10
	15	1	0.1953391E+10	0.1951582E+10	0.1968682E+10	0.2012316E+10
		2	0.1820178E+10	0.1777576E+10	0.1859877E+10	0.1862845E+10
		3	0.2020148E+10	0.2010180E+10	0.2040320E+10	0.2075821E+10
		4	0.1929308E+10	0.1943816E+10	0.1934836E+10	0.1994736E+10
	14	1	0.1756927E+10	0.1758346E+10	0.1769514E+10	0.1811857E+10
		2	0.1643547E+10	0.1609922E+10	0.1677458E+10	0.1684811E+10
		3	0.1814058E+10	0.1808467E+10	0.1830910E+10	0.1866254E+10
		4	0.1740582E+10	0.1756018E+10	0.1744640E+10	0.1800978E+10
	13	1	0.1572695E+10	0.1576669E+10	0.1582941E+10	0.1623570E+10
		2	0.1476921E+10	0.1450991E+10	0.1505704E+10	0.1516408E+10
		3	0.1621286E+10	0.1619280E+10	0.1635240E+10	0.1669884E+10
		4	0.1562757E+10	0.1578694E+10	0.1565589E+10	0.1618187E+10
	12	1	0.1399928E+10	0.1405854E+10	0.1408161E+10	0.1446711E+10
		2	0.1319724E+10	0.1300324E+10	0.1343978E+10	0.1357112E+10
		3	0.1440965E+10	0.1441826E+10	0.1452402E+10	0.1485869E+10
		4	0.1395202E+10	0.1411259E+10	0.1397026E+10	0.1445743E+10
	11	1	0.1237910E+10	0.1245245E+10	0.1244422E+10	0.1280584E+10
		2	0.1171416E+10	0.1157490E+10	0.1191682E+10	0.1206428E+10
		3	0.1272284E+10	0.1275366E+10	0.1281547E+10	0.1313425E+10
		4	0.1237322E+10	0.1253161E+10	0.1238333E+10	0.1283060E+10

year		X_2			
	Options	1	2	3	4
10	1	0.1085969E+10	0.1094224E+10	0.1091025E+10	0.1124533E+10
	2	0.1031487E+10	0.1022077E+10	0.1048254E+10	0.1063888E+10
	3	0.1114485E+10	0.1119207E+10	0.1121883E+10	0.1151816E+10
	4	0.1088557E+10	0.1103878E+10	0.1088928E+10	0.1129586E+10
9	1	0.9434762E+09	0.9522143E+09	0.9473099E+09	0.9779446E+09
	2	0.8994570E+09	0.8936969E+09	0.9131648E+09	0.9290488E+09
	3	0.9668607E+09	0.9726992E+09	0.9726693E+09	0.1000354E+10
	4	0.9483795E+09	0.9629170E+09	0.9482636E+09	0.9847985E+09
8	1	0.8098402E+09	0.8186720E+09	0.8126633E+09	0.8402416E+09
	2	0.7748732E+09	0.7719824E+09	0.7859203E+09	0.8014924E+09
	3	0.8287490E+09	0.8352363E+09	0.8332169E+09	0.8583939E+09
	4	0.8162925E+09	0.8298134E+09	0.8158260E+09	0.8482067E+09
7	1	0.6845083E+09	0.6930869E+09	0.6865089E+09	0.7108826E+09
	2	0.6573099E+09	0.6565844E+09	0.6660545E+09	0.6808231E+09
	3	0.6995319E+09	0.7062496E+09	0.7028812E+09	0.7253340E+09
	4	0.6918278E+09	0.7041281E+09	0.6911308E+09	0.7193466E+09
6	1	0.5669621E+09	0.5749800E+09	0.5683076E+09	0.5893595E+09
	2	0.5463659E+09	0.5471727E+09	0.5531300E+09	0.5666670E+09
	3	0.5786317E+09	0.5852073E+09	0.5810609E+09	0.6006098E+09
	4	0.5745444E+09	0.5854467E+09	0.5737225E+09	0.5977804E+09
5	1	0.4567156E+09	0.4639011E+09	0.4575548E+09	0.4751951E+09
	2	0.4416631E+09	0.4434344E+09	0.4467361E+09	0.4586705E+09
	3	0.4655085E+09	0.4716112E+09	0.4671945E+09	0.4836936E+09
	4	0.4640270E+09	0.4733781E+09	0.4631727E+09	0.4830953E+09
4	1	0.3533134E+09	0.3594276E+09	0.3537781E+09	0.3679414E+09
	2	0.3428455E+09	0.3450732E+09	0.3464867E+09	0.3564993E+09
	3	0.3596579E+09	0.3649948E+09	0.3607580E+09	0.3740911E+09
	4	0.3598841E+09	0.3675530E+09	0.3590784E+09	0.3749018E+09
3	1	0.2563285E+09	0.2611625E+09	0.2565354E+09	0.2671779E+09
	2	0.2495775E+09	0.2518083E+09	0.2520190E+09	0.2598374E+09
	3	0.2606083E+09	0.2649216E+09	0.2612621E+09	0.2713398E+09
	4	0.2617473E+09	0.2676226E+09	0.2610603E+09	0.2728325E+09
2	1	0.1653608E+09	0.1687329E+09	0.1654124E+09	0.1725098E+09
	2	0.1615430E+09	0.1633736E+09	0.1629923E+09	0.1683860E+09
	3	0.1679189E+09	0.1709827E+09	0.1682500E+09	0.1750067E+09
	4	0.1692692E+09	0.1732579E+09	0.1687617E+09	0.1765407E+09
1	1	0.8003516E+08	0.8178837E+08	0.8002157E+08	0.8356654E+08
	2	0.7844405E+08	0.7951709E+08	0.7908635E+08	0.8186257E+08
	3	0.8117781E+08	0.8279499E+08	0.8129540E+08	0.8468661E+08
	4	0.8212285E+08	0.8414813E+08	0.8184690E+08	0.8569937E+08

Table 5: The second implementation results of the model test

	year	Options	X_2 1	2	3	4
X_1	20	1	0.2732308E+10	0.2749728E+10	0.2779261E+10	0.2916686E+10
		2	0.2575695E+10	0.2540523E+10	0.2674569E+10	0.2787827E+10
		3	0.2906419E+10	0.2913321E+10	0.2963756E+10	0.2944702E+10
		4	0.2979226E+10	0.3017683E+10	0.3005411E+10	0.3152502E+10
	19	1	0.2516812E+10	0.2534958E+10	0.2557528E+10	0.2683650E+10
		2	0.2377589E+10	0.2348733E+10	0.2464565E+10	0.2568508E+10
		3	0.2670020E+10	0.2678766E+10	0.2719989E+10	0.2841674E+10
		4	0.2736005E+10	0.2772951E+10	0.2758217E+10	0.2893210E+10
	18	1	0.2312426E+10	0.2331043E+10	0.2347538E+10	0.2462996E+10
		2	0.2189170E+10	0.2165934E+10	0.2265365E+10	0.2360520E+10
		3	0.2446690E+10	0.2456937E+10	0.2490019E+10	0.2601417E+10
		4	0.2506336E+10	0.2541695E+10	0.2525015E+10	0.2648595E+10
	17	1	0.2118572E+10	0.2137426E+10	0.2148665E+10	0.2254063E+10
		2	0.2009947E+10	0.1991682E+10	0.2076394E+10	0.2163257E+10
		3	0.2235704E+10	0.2247133E+10	0.2273067E+10	0.2374758E+10
		4	0.2289463E+10	0.2323164E+10	0.2305014E+10	0.2417826E+10
	16	1	0.1934705E+10	0.1953576E+10	0.1960315E+10	0.2056223E+10
		2	0.1839454E+10	0.1825553E+10	0.1897107E+10	0.1976150E+10
		3	0.2036376E+10	0.2048692E+10	0.2068395E+10	0.2160930E+10
		4	0.2084672E+10	0.2116652E+10	0.2097465E+10	0.2200119E+10
	15	1	0.1760305E+10	0.1778990E+10	0.1781928E+10	0.1868883E+10
		2	0.1677252E+10	0.1667147E+10	0.1726992E+10	0.1798656E+10
		3	0.1848061E+10	0.1860988E+10	0.1875308E+10	0.1959204E+10
		4	0.1891288E+10	0.1921488E+10	0.1901664E+10	0.1994736E+10
	14	1	0.1594882E+10	0.1613192E+10	0.1612974E+10	0.1691483E+10
		2	0.1522922E+10	0.1516083E+10	0.1565562E+10	0.1630265E+10
		3	0.1670149E+10	0.1683429E+10	0.1693150E+10	0.1768898E+10
		4	0.1708674E+10	0.1737044E+10	0.1716947E+10	0.1800978E+10
	13	1	0.1437970E+10	0.1455732E+10	0.1452950E+10	0.1523491E+10
		2	0.1376068E+10	0.1372000E+10	0.1412357E+10	0.1470493E+10
		3	0.1502062E+10	0.1515458E+10	0.1521304E+10	0.1589363E+10
		4	0.1536229E+10	0.1562722E+10	0.1542685E+10	0.1618187E+10
	12	1	0.1289128E+10	0.1306181E+10	0.1301381E+10	0.1364404E+10
		2	0.1236314E+10	0.1234557E+10	0.1266943E+10	0.1318883E+10
		3	0.1343256E+10	0.1356547E+10	0.1359184E+10	0.1419991E+10
		4	0.1373384E+10	0.1397961E+10	0.1378287E+10	0.1445743E+10
	11	1	0.1147938E+10	0.1164134E+10	0.1157817E+10	0.1213748E+10
		2	0.1103304E+10	0.1103429E+10	0.1128908E+10	0.1175004E+10
		3	0.1193217E+10	0.1206199E+10	0.1206241E+10	0.1260206E+10
		4	0.1219606E+10	0.1242230E+10	0.1223195E+10	0.1283060E+10

year	Options	X_2			
		1	2	3	4
10	1	0.1014003E+10	0.1029207E+10	0.1021832E+10	0.1071073E+10
	2	0.9766991E+09	0.9783075E+09	0.9978640E+09	0.1038446E+10
	3	0.1051459E+10	0.1063944E+10	0.1061956E+10	0.1109465E+10
	4	0.1074386E+10	0.1095028E+10	0.1076881E+10	0.1129586E+10
9	1	0.8869478E+09	0.9010344E+09	0.8930232E+09	0.9359528E+09
	2	0.8561800E+09	0.8589010E+09	0.8734425E+09	0.9088227E+09
	3	0.9175242E+09	0.9293376E+09	0.9258370E+09	0.9672567E+09
	4	0.9372487E+09	0.9558815E+09	0.9388493E+09	0.9847985E+09
8	1	0.7664167E+09	0.7792722E+09	0.7710094E+09	0.8079846E+09
	2	0.7414423E+09	0.7449320E+09	0.7552957E+09	0.7857687E+09
	3	0.7909784E+09	0.8019607E+09	0.7974232E+09	0.8330980E+09
	4	0.8077421E+09	0.8243440E+09	0.8086307E+09	0.8482067E+09
7	1	0.6520719E+09	0.6635925E+09	0.6554295E+09	0.6867874E+09
	2	0.6321978E+09	0.6361375E+09	0.6430943E+09	0.6689379E+09
	3	0.6714127E+09	0.6814172E+09	0.6762781E+09	0.7065332E+09
	4	0.6854409E+09	0.6999939E+09	0.6857829E+09	0.7193466E+09
6	1	0.5435936E+09	0.5536850E+09	0.5459418E+09	0.5720003E+09
	2	0.5281728E+09	0.5322677E+09	0.5365270E+09	0.5580031E+09
	3	0.5584409E+09	0.5673330E+09	0.5619903E+09	0.5871324E+09
	4	0.5699430E+09	0.5824331E+09	0.5698888E+09	0.5977804E+09
5	1	0.4406785E+09	0.4492553E+09	0.4422228E+09	0.4632820E+09
	2	0.4291081E+09	0.4330857E+09	0.4352992E+09	0.4526550E+09
	3	0.4516979E+09	0.4593549E+09	0.4541716E+09	0.4744901E+09
	4	0.4608692E+09	0.4712857E+09	0.4605548E+09	0.4830953E+09
4	1	0.3430393E+09	0.3500245E+09	0.3439666E+09	0.3603094E+09
	2	0.3347574E+09	0.3383662E+09	0.3391318E+09	0.3526007E+09
	3	0.3508392E+09	0.3571491E+09	0.3524558E+09	0.3682239E+09
	4	0.3578611E+09	0.3661968E+09	0.3574095E+09	0.3749018E+09
3	1	0.2504035E+09	0.2557280E+09	0.2508832E+09	0.2627766E+09
	2	0.2448872E+09	0.2478958E+09	0.2477613E+09	0.2575632E+09
	3	0.2555390E+09	0.2604003E+09	0.2564976E+09	0.2679727E+09
	4	0.2605806E+09	0.2668315E+09	0.2601025E+09	0.2728325E+09
2	1	0.1625128E+09	0.1661150E+09	0.1626984E+09	0.1703942E+09
	2	0.1592760E+09	0.1614714E+09	0.1609379E+09	0.1672803E+09
	3	0.1654900E+09	0.1688109E+09	0.1659709E+09	0.1733961E+09
	4	0.1687085E+09	0.1728733E+09	0.1683036E+09	0.1765407E+09
1	1	0.7912235E+08	0.8094748E+08	0.7915264E+08	0.8288846E+08
	2	0.7771342E+08	0.7890051E+08	0.7842530E+08	0.8150417E+08
	3	0.8040180E+08	0.8209933E+08	0.8056841E+08	0.8417284E+08
	4	0.8194311E+08	0.8402346E+08	0.8170076E+08	0.8569937E+08

Table 6: The third implementation results of the model test

	year	Options	X_2 1	2	3	4
X_1	20	1	0.2353533E+10	0.2387499E+10	0.2384151E+10	0.2529179E+10
		2	0.2258601E+10	0.2253544E+10	0.2327745E+10	0.2454841E+10
		3	0.2474451E+10	0.2500613E+10	0.2512774E+10	0.2654215E+10
		4	0.2563935E+10	0.2613511E+10	0.2579143E+10	0.2731343E+10
	19	1	0.2166984E+10	0.2199917E+10	0.2193146E+10	0.2326245E+10
		2	0.2083205E+10	0.2081262E+10	0.2143693E+10	0.2260335E+10
		3	0.2273072E+10	0.2299030E+10	0.2306100E+10	0.2435907E+10
		4	0.2354577E+10	0.2401460E+10	0.2367009E+10	0.2506691E+10
	18	1	0.1990166E+10	0.2021951E+10	0.2012353E+10	0.2134199E+10
		2	0.1916584E+10	0.1917314E+10	0.1969255E+10	0.2076036E+10
		3	0.2082839E+10	0.2108413E+10	0.2111123E+10	0.2229956E+10
		4	0.2156890E+10	0.2201097E+10	0.2166883E+10	0.2294756E+10
	17	1	0.1822568E+10	0.1853099E+10	0.1841222E+10	0.1952452E+10
		2	0.1758284E+10	0.1761274E+10	0.1803915E+10	0.1901391E+10
		3	0.1903134E+10	0.1928157E+10	0.1927184E+10	0.2035663E+10
		4	0.1970221E+10	0.2011769E+10	0.1978085E+10	0.2094816E+10
	16	1	0.1663705E+10	0.1692886E+10	0.1679234E+10	0.1780448E+10
		2	0.1607877E+10	0.1612741E+10	0.1647182E+10	0.1735882E+10
		3	0.1733372E+10	0.1757689E+10	0.1753656E+10	0.1852367E+10
		4	0.1793956E+10	0.1832864E+10	0.1799974E+10	0.1906194E+10
	15	1	0.1513120E+10	0.1540862E+10	0.1525897E+10	0.1617663E+10
		2	0.1464957E+10	0.1471336E+10	0.1498597E+10	0.1579016E+10
		3	0.1573000E+10	0.1596470E+10	0.1589950E+10	0.1679447E+10
		4	0.1627513E+10	0.1663800E+10	0.1631945E+10	0.1728249E+10
	14	1	0.1370377E+10	0.1396600E+10	0.1380746E+10	0.1463598E+10
		2	0.1329137E+10	0.1336699E+10	0.1357721E+10	0.1430329E+10
		3	0.1421499E+10	0.1443989E+10	0.1435511E+10	0.1516314E+10
		4	0.1470343E+10	0.1504030E+10	0.1473426E+10	0.1560376E+10
	13	1	0.1235066E+10	0.1259695E+10	0.1243342E+10	0.1317785E+10
		2	0.1200055E+10	0.1208487E+10	0.1224142E+10	0.1289381E+10
		3	0.1278375E+10	0.1299765E+10	0.1289813E+10	0.1362416E+10
		4	0.1321929E+10	0.1353038E+10	0.1323881E+10	0.1402005E+10
	12	1	0.1106795E+10	0.1129766E+10	0.1113267E+10	0.1179777E+10
		2	0.1077364E+10	0.1086378E+10	0.1097471E+10	0.1155757E+10
		3	0.1143164E+10	0.1163344E+10	0.1152363E+10	0.1217228E+10
		4	0.1181782E+10	0.1210336E+10	0.1182800E+10	0.1252599E+10
	11	1	0.9851971E+09	0.1006450E+10	0.9901289E+09	0.1049155E+10
		2	0.9607376E+09	0.9700652E+09	0.9773378E+09	0.1029065E+10
		3	0.1015427E+10	0.1034295E+10	0.1022693E+10	0.1080259E+10
		4	0.1049440E+10	0.1075463E+10	0.1049705E+10	0.1111650E+10

year	Options	X_2 1	2	3	4
10	1	0.8699214E+09	0.8894024E+09	0.8735549E+09	0.9255203E+09
	2	0.8498654E+09	0.8592585E+09	0.8633941E+09	0.9089343E+09
	3	0.8947498E+09	0.9122132E+09	0.9003623E+09	0.9510427E+09
	4	0.9244678E+09	0.9479838E+09	0.9241431E+09	0.9786786E+09
9	1	0.7606371E+09	0.7782994E+09	0.7631929E+09	0.8084976E+09
	2	0.7444536E+09	0.7536825E+09	0.7553103E+09	0.7950133E+09
	3	0.7807403E+09	0.7967159E+09	0.7849563E+09	0.8291406E+09
	4	0.8064535E+09	0.8274891E+09	0.8056889E+09	0.8532342E+09
8	1	0.6570304E+09	0.6728325E+09	0.6587097E+09	0.6977305E+09
	2	0.6442238E+09	0.6530764E+09	0.6527745E+09	0.6869707E+09
	3	0.6730291E+09	0.6874413E+09	0.6760827E+09	0.7141386E+09
	4	0.6950090E+09	0.7135909E+09	0.6939397E+09	0.7348905E+09
7	1	0.5588041E+09	0.5727098E+09	0.5597899E+09	0.5928827E+09
	2	0.5489122E+09	0.5571928E+09	0.5554920E+09	0.5844931E+09
	3	0.5712672E+09	0.5840478E+09	0.5733717E+09	0.6056462E+09
	4	0.5897677E+09	0.6059234E+09	0.5885159E+09	0.6232454E+09
6	1	0.4656768E+09	0.4776548E+09	0.4661354E+09	0.4936357E+09
	2	0.4582689E+09	0.4657974E+09	0.4631840E+09	0.4872841E+09
	3	0.4751247E+09	0.4862128E+09	0.4764746E+09	0.5032948E+09
	4	0.4903834E+09	0.5041412E+09	0.4890595E+09	0.5179198E+09
5	1	0.3773817E+09	0.3874055E+09	0.3774641E+09	0.3996884E+09
	2	0.3720568E+09	0.3786679E+09	0.3755871E+09	0.3950635E+09
	3	0.3842902E+09	0.3936315E+09	0.3850622E+09	0.4067369E+09
	4	0.3965294E+09	0.4079183E+09	0.3952327E+09	0.4185561E+09
4	1	0.2936663E+09	0.3017137E+09	0.2935090E+09	0.3107560E+09
	2	0.2900512E+09	0.2955934E+09	0.2924518E+09	0.3075663E+09
	3	0.2984698E+09	0.3060162E+09	0.2988241E+09	0.3156446E+09
	4	0.3078972E+09	0.3169468E+09	0.3067168E+09	0.3248168E+09
3	1	0.2142912E+09	0.2203443E+09	0.2140176E+09	0.2265690E+09
	2	0.2120394E+09	0.2163741E+09	0.2135425E+09	0.2245419E+09
	3	0.2173857E+09	0.2230952E+09	0.2174674E+09	0.2297084E+09
	4	0.2241956E+09	0.2309361E+09	0.2232113E+09	0.2363834E+09
2	1	0.1390298E+09	0.1430745E+09	0.1387510E+09	0.1468725E+09
	2	0.1378195E+09	0.1408204E+09	0.1386361E+09	0.1457535E+09
	3	0.1407756E+09	0.1446115E+09	0.1407158E+09	0.1486366E+09
	4	0.1451495E+09	0.1496117E+09	0.1444325E+09	0.1529557E+09
1	1	0.6766722E+08	0.6969309E+08	0.6748307E+08	0.7142558E+08
	2	0.6720017E+08	0.6875260E+08	0.6752177E+08	0.7097681E+08
	3	0.6839166E+08	0.7032284E+08	0.6830865E+08	0.7215367E+08
	4	0.7049930E+08	0.7271455E+08	0.7011285E+08	0.7425035E+08

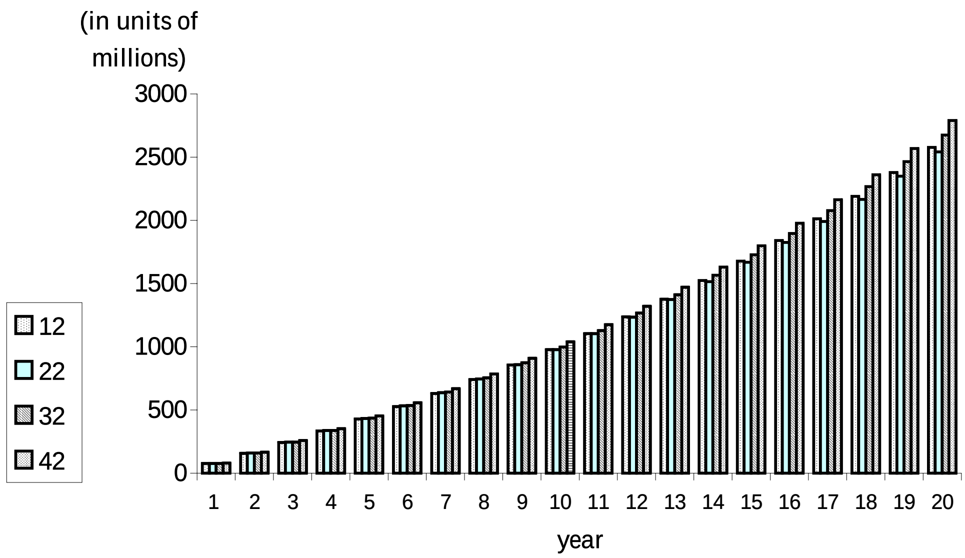

Figure 9: The second implementation results of the model test

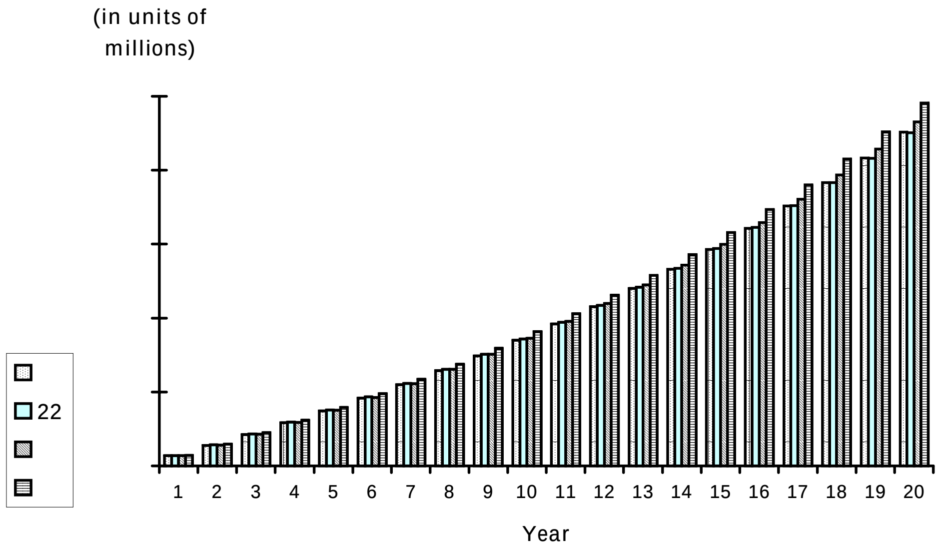

Figure 10: The third implementation results of the model test