Generation Expansion Planning

1. Introduction

- Generation Expansion Planning(GEP) is the first crucial step in long-term planning issues, after the load is properly forecasted for a specified future period.
- GEP is, in fact, the problem of determining when, what and where the generation plants are required so that the loads are adequately supplied for a foreseen future.

2. Problem Definition

- Generally speaking, GEP, is an optimization problem in which the aim is to determine the new generation plants in terms of when to be available, what type and capacity they should be and,
- Where to allocate so that an objective function is optimized and various constraints are met.
- It may be of static type in which the solution is found only for a specified stage (static type typically, year) or a dynamic type, in which,
- The solution is found for several stages in a specified period. The objective function consists, generally, of.

Objective function = Capital costs + Operation costs

- The first term is, mainly due to
  - Investment costs (Cinv)
  - Salvation value of investment costs (Csalv)
  - Fuel inventory costs (Ctv)
- While, the second term, consists, mainly, of
  - Fuel costs (Cfuel)
  - Non-fuel operation and maintenance costs (Co&M)
  - Cost of energy not served (CENs)

3. Problem Description

- Let us consider a case in which the aim is to determine the generation capacity for year t in which the peak load is PLt.
- If PGt denotes the available generating capacity in year t, it will be a function of Kt, where:

Kt = Already committed units + New units additions - Units retired

(Already committed units - from previous period. New units additions — to be determined. Units retired — due to age.)

- Moreover, if Rest denotes the minimum reserve margin (in %), the following inequality should be met:

$$(1 + Rest/100)\, PLt \leq PGt$$

- Moreover, suppose the available plant candidate plants are:
  - A: 150 MW thermal power plant (with oil fuel)
  - B: 250 MW thermal power plant (with coal fuel)
  - C: 100 MW gas turbine power plant (with natural gas fuel)
- Let us assume that, the existing capacity is 500 MW, consisting of two already committed units (2 x 250), denoted by D. The plants specifications are provided in Table 1.

Table 1 Plants data

Unit name	Max capacity (MW)	Investment cost (R/kW)	Plant life (Year)	Fuel cost[a] (R/MWh)	Fixed O&M cost (R/kW month)	Variable O&M cost (R/MWh)	Scheduled maintenance (day/year)
A	150	300	20	20.409	1	1	10
B	250	350	30	14.000	3	3	30
C	100	250	25	25.953	2.5	2.5	50
D	250	–	–	14.355	–		–

[a] The fuel cost is considered to be independent of the operating point

Some of the terms in Table 1 are defined as follows:

Investment cost.

This term represents the cost of a power plant, in terms of R/kW. The total investment cost is the product of this value with the power plant capacity.

Plant life.

Two plants with the same total investment costs, but with different lives, have different values. If the plant life is say, 20 years, and the study period is say, 5 years, at the end of this period, still some values are left, defined as salvation value.

- This value will be deducted from the capital cost so that the actual investment cost can be determined.
- Discount rate should be given in order to calculate the salvation value.
- A very simple, but unrealistic choice is to consider this rate to be zero. In that case, after 5 years, 15/20 of its value is left (salvation value).

Fuel cost.

The fuel cost of a plant is, in fact, dependent on its production level (i.e. f(PG)). In other words, the cost varies with the production level.

- For simplicity, the cost (R/MWh) is considered to be fixed here. Total cost is calculated from the product of this value and the energy production of the unit.

O & M cost parameters.

- Operation and Maintenance (O & M) is the process required for the proper operation of power plants, defined in terms of the number of days per year.
- Two cost parameters are also normally defined for maintenance:
  - A fixed term, independent of energy production (in terms of R /kW month); the total value is calculated from the product of this value times the plant capacity times 12 (12 months).
  - A variable term, defined in terms of R/MWh. Note that the total variable cost is affected by the period of maintenance, as during these days, the plant does not generate any power.

More Practical Situation:

we are going to observe the following points:

- Suppose that our study period extends for several years.
- The planning problem may be described as a dynamic type; in which, the capital as well as the operation costs should be minimized for the whole period.
- The Net Present Values (NPV) should be calculated based on a given discount rate.
- It is assumed that full investment cost for a plant is made at beginning of the year in which it goes into service.

- The operational costs may be assumed to occur in the middle of each year.
- The salvation costs are assumed to occur at the end of each year.
- The load may not be constant throughout a year. Instead it can be described by a non-flat Load Duration Curve, either in a continuous or discrete way.
- The continuous type may be in the form of a polynomial function.
  - The discrete specified period. type may be defined as several levels, each of which by a specified period.
  - A typical continuous type may be in the form of

  Normalized load = $1 - 3.6D + 16.6D^2 - 36.8D^3 + 36D^4 - 12.8D^5 \quad 0 \leq D \leq 1$
- A typical normalized load duration curve LDC is shown in Fig. (1).

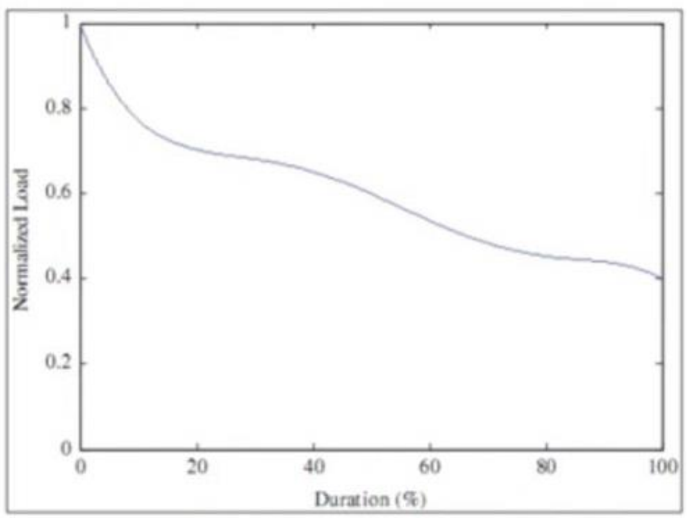

Fig. 1 Normalized LDC

- A typical discrete type is shown in Fig. (2).

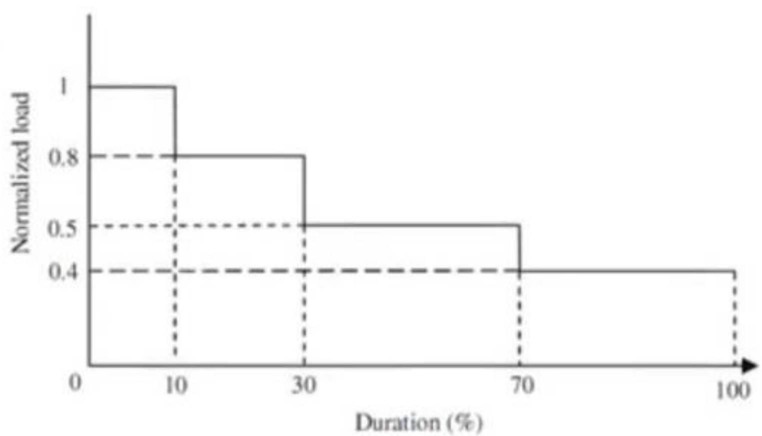

Fig. 2 A typical discrete LDC

- Besides defining a reserve margin, what happens if we also consider a reliability index for our solution, such as Loss Of Load Probability (LOLP)?
- In fact, although power plants are maintained regularly, they may have unexpected outage due to any reason.
- The probability of such a failure is defined as Forced Outage Rate (FOR).
- If the FOR of a unit is, say, 5%, it means that the plant would be available only for 95% of the time it is anticipated to be in service.
- The LOLP of the overall generation resources is calculated based on the given FORs of the plants and the anticipated load.
- These FORs are normally known based on the historical data of the plants.
- Both the LOLP and the reserve margin may be simultaneously considered.
- Suppose two different plans result in acceptable performances in terms of LOLP.
- One way to differentiate between these two plans is to consider the cost of Energy Not Served (ENS); as a lower LOLP implies less ENS.
- This cost may be calculated by ENS (which, in turn, may be calculated from LOLP) times the per unit cost of ENS (given by the user).
- We note that the problem can be quite complex if all the above mentioned points are to be considered.
- In the following section, we develop a basic mathematical formulation of the problem in which some terms may be ignored or simplified.
- For instance, salvation value is ignored and the operation and maintenance cost is considered to be a function of only the unit capacity (the variable term, ignored).

4. Mathematical Development

- The problem is to determine from a list of available options, the number, type and capacity of each unit needed, in each year of the study period.
- In doing so, the total costs incurred should be minimized while various constraints, such as meeting the load, should be satisfied.
- If the decision variable is denoted by X,, representing the number of unit type i for year t, the objective function terms and the constraints are described in the following subsections.

Objective Functions

- Total cost, Gtotal, to be minimized may be described as:(It is understood that all costs mentioned should be calculated, once referred to base year.)
  Ctoral = Cinv + Cfuel + Co&m + CENS
  where :
  - Cin: The investment cost.
  - Cfuel: The fuel cost.
  - Co&m: The operation and maintenance cost
  - CENS: The cost of energy not served

  The details are as follows.

The Investment Cost

If Xit represents the number of unit type i required in year t, Cinv is given by

$$Cinv = \sum_{t=1}^{T} \sum_{i=1}^{Ng} Cost_{Invit}.PGi.Xit$$

Where:

- Cost_Invit: The cost in R/MW for unit type i in year t
- PGi: The capacity of unit i (MW)
- T: The study period (in years)
- Ng: The number of units types

The Fuel Cost

- The fuel cost of each unit is a function of its energy output, normally in a nonlinear form.
- However, for simplicity, here we assume a linear function given by:
  (Various approaches may be used in calculating the energy outputs of the units. One simple way is to rank the units according to their fuel costs. Then, total energy requirement is distributed among the units; based on the above ranking.)

$$Cfuel = \sum_{t=1}^{T}\left(\sum_{i=1}^{Ng} Cost_{Fuelit}.Energyit.Xit + Cost\_Fuelet\right)$$

Where:

- Cost_Fuelit: The cost of fuel (in R/MWh) for unit type i in year t
- Energyit: Energy output for unit type i in year t
- Cost_Fuelet: The fuel cost of existing units in year t

The Operation and Maintenance Cost

- Similar to Cinv, the operation and maintenance cost is given as a linear function of PG, given by:

$$CO\&M = \sum_{t=1}^{T}\sum_{i=1}^{Ng} CostO\&Mit.PGi.Xit$$

Where:

- Cost O&Mit: The operation and maintenance cost (in R/MW) for unit type i in year t
- Xit: The number of unit type i required in year t
- Ng: The number of units types

The Cost of Energy not Served

- A generation unit may be tripped out in a rate given by its Forced Outage Rate (FOR).
- It represents the percentage of a time; the unit may be unavailable due to unexpected outages.
- Due to the FORs of the units and based on the demand and the available reserve, some portion of the energy demand cannot be served.
- The so called Energy Not Served (ENS) cannot be made zero, but should be minimized as a cost term. It is given by:

$$CENS = \sum_{t=1}^{T} Cost_{ENSt}.ENSt$$

Where:

- Cost_ENSt: The cost of the energy not served in year t (R/MWh)
- ENSt: The energy not served in year t (MWh)

Constraints

- Some constraints have to be observed during the optimization process.

Technical Constraints

- The generation capacity should be sufficient in meeting the load while some uncertainties are involved and the generation units may be, unexpectedly, tripped out at any time. The following two constraints may, thus, be considered

$$(1 + Rest/100)Plt \leq \sum_{i=1}^{Ng} PGi.Xit + PGt \qquad \forall t = 1, \ldots, T$$

$$LOLPt < \overline{LOLP} \qquad \forall t = 1, \ldots, T$$

Where:

- Rest: The required reserve in year t
- PGi: The capacity of unit i (MW)
- Xit: The number of unit type i required in year t
- PLt: The load in year t
- Ng: The number of units types
- PGt: The capacity available due to existing units in year t (The existing units are, in fact, the units available and justified up to that time)
- LOLP: The Loss Of Load Probability in year t
- $\overline{LOLP}$: The maximum acceptable LOLP

- The first constraint shows that the generation capacity should meet the load plus a reserve.
- LOLP is a reliability index normally used to represent the system robustness in response to elements contingencies.

Fuel Constraint

Fuel type j in year t $\overline{Fueljt}$, may be limited to based on its availability for the system. As a result:

$$Fuelejt + \sum_{i=1}^{Ng} Fuelij.Energyit.Xit \leq \overline{Fueljt} \qquad \forall j \in Nf \text{ and } \forall t = 1, \ldots, T$$

Where:

- Fuelejt: The fuel consumption type j for existing units in year t (m^3)
- Fuelij: The fuel consumption type j for unit type i (m^3/MWh)
- Energyit: Energy output for unit type i in year t
- Xit: The number of units type i required in year t
- Ng: The number of unit types
- Nf: The number of the available fuels

Pollution Constraint

Similar to fuel, the pollution generated by unit i based on pollution type j (Polluij) should be limited to $\overline{Pollujt}$, so

$$Polluejt + \sum_{i=1}^{Ng} Polluij.Energyit.Xit \leq \overline{Pollujt} \qquad \forall t = 1, \dots, T$$

Where:

- Np: The number of pollution types
- Polluejt: The pollution type j, generated by existing units in year t
- Energyit: Energy output for unit type i in year t
- Xit: The number of unit type i required in year t
- Ng: The number of units types

WASP, a GEP Package

- WASP is a GEP package, based on single-bus modeling designed to find the economically optimal generation expansion policy for an electric utility system within user-specified constraints.
- It utilizes probabilistic estimation of the system (production costs), unserved energy cost, reliability calculations.
- It utilizes LP (Linear Programming) technique for determining optimal dispatch policy satisfying constraints on fuel availability, environmental emissions and electricity generation by some plants.
- It utilizes DP (Dynamic Programming) for comparing the costs of alternative system expansion plans.
- Generation technology data for some generation plants are given in Table 2

Table 2 Generation technology data for some generation plants.

Technology type	Cost_Inv (investment cost) (R/kW)	T (plant life) (year)	Fuel cost (R/MWh)
A	400	30	18
B	300	20	20
C	250	25	26