

Economics of Traditional Planning Methods

1.0 Introduction

These notes are partly adaptations of information from four sources in the bibliography [1], [2], [3, ch. 5], with some information obtained from a few other sources also listed in the bibliography. These sources provide an excellent treatment of traditional electric utility economic planning procedures. In spite of the fact that the electric utility industry has changed significantly since the development of some of this material, the principles outlined are still heavily used in the planning done by regulated utilities.

The implicit assumption of material treated in these notes is that the planner has become aware that future operation of the existing system has non-negligible potential to result in violation of electric reliability criteria or undesirably high costs (including “costs” associated with lost opportunities). Therefore it is of interest to identify possible alternative decision paths that can be taken.

So the objective of economic analysis is to determine the economic consequences of project alternatives so that management can make an informed decision in selecting the most desirable alternative.

Two issues always important in planning decisions are

1. What is the investment cost of each alternative?
2. How is yearly operational cost impacted by each alternative?

2.0 Types of expenditures

Expenditures incurred on a project can be divided into two types: capital investments and maintenance & operation (M&O) expenses, i.e., *investments* and *expenses*.

Investment is the amount of money required to purchase or construct an asset having a service life beyond a year.

An expense is the amount of money required to own, operate, and maintain existing assets and also includes the amount of money required to purchase or construct assets having a service life of one year or less. Expenses may be categorized into two forms:

1. Operation and maintenance (O&M) costs are generally divided into three parts:
 - a. Fuel costs (for generation facilities)
 - b. Variable O&M (VOM): includes non-fuel costs that are a function of production
 - c. Fixed O&M: includes salaries and scheduled maintenance
2. Fixed costs are related to the amount of capital invested in the asset. There are typically five kinds of fixed costs:
 - a. Cost of capital (return on investment): The return to the stockholders helping to finance the project, or the interest on bonds used to finance the project. Bond interest paid, unlike dividends on stock, is deductible as a business expense in the computation of federal and state income taxes.
 - b. Depreciation: This captures the fact that all facilities decrease in worth over time as they wear out physically.

It is an expense that systematically returns capital to the investors as an asset declines in value. There are different methods of computing depreciation. The simplest of these is the so-called “straight-line” depreciation method where each year’s depreciation is $(1/N) \times \text{Investment Cost}$ for a facility with a book life of N years.

- c. Federal and state income taxes: Taxes levied on the basis of income, paid to federal and state governments.
- d. Ad valorem (property) tax: Tax levied on the basis of property values and paid to local jurisdictions such as county governments or school districts.
- e. Insurance costs: The costs of premiums for insurance policies or expenses of self-insurance programs.

The above fixed charges are often captured in total using the so-called “fixed charge rate.” Non-levelized fixed charge rates have an annual variation that might begin at 28%/year and decrease to a value of 14%/year at age 30 years as interest decreases. Levelized fixed charge rates over the life of the facility can range from 18-22%/year.

Detailed computation of each of the above components of the fixed charge rate is outlined in [2, pp. 58-64].

3.0 Cost of capital

3.1 Assets

A very basic concept of which you need to be aware is that of the electric utility balance sheet. The left-hand-side of the balance sheet lists all of the *assets*:

- Plant (facilities) at original costs

- Less depreciation,
- Plus construction work in progress,
- Plus cash, accounts receivable, materials/supplies on hand

3.2 Liabilities and owner's equity

The right-hand-side of the balance sheet lists the *liabilities* and *owner's equity*:

- Long-term debt: Money the utility has borrowed through bonds at a stipulated interest rate and a stipulated maturity
- Total owner's equity: Utilities issue stock on the stock exchanges, which permits public ownership of the utility.

There are two forms:

- Common stock: This is usually where the bulk of ownership resides. Each common stockholder is entitled to vote in electing the board of directors. But common stock has no fixed yield but rather, dividends are paid to each stockholder at the end of the year in proportion to the company's annual profit and the number of shares owned by the stockholder. *This dividend is according to the regulators allowed rate of return.*
- Preferred stock: This has a fixed yield but no vote.
- Current liabilities: This includes short-term debt, accounts payable, and customer deposits.

The *accounting equation* of the balance sheet is then very sensible:

$$\text{Assets} = \text{Liabilities} + \text{Owner's Equity} \quad (1)$$

3.3 Discount rate

The discount rate is typically a weighted average over the different interest rates paid for the cost of capital. For example, a utility could finance its new assets as follows:

- 50% with bonds at an interest of 7%
- 10% with preferred stock at a dividend yield of 11%
- 40% with common stock expected to achieve a (regulated) 15% return

So the discount rate is computed as

$$i=0.5*0.07+0.1*0.11+0.4*0.15=0.0746$$

Therefore, the discount rate would be 7.46%.

The discount rate is the annual payment as a percentage of the amount owed.

The discount rate may also be thought of as reflecting the value given to possession of money now rather than later, since having it now allows it to be invested (in the same financial markets) to earn a return. In this sense, the discount rate is the annual income as a percentage of the amount invested, i.e., the average interest rate.

Note that the discount rate does *not* reflect the effects of inflation. Inflation changes the buying power of money. Neither does the discount rate reflect depreciation. Depreciation reflects the reduced value of the facilities. The discount rate reflects only the cost of borrowed money. The fixed charge rate reflects the cost of borrowed money and depreciation, but not inflation.

4.0 Time value of money

Amounts of money at different points in time cannot be directly compared due to the time value of money.

The value of money received today is higher than the same amount of money received in the future because money received today can be invested to yield the original investment plus interest. Therefore, in order to compare alternatives having cash flows at different times, amounts of money must be expressed in equivalent amounts at common points in time.

The process of calculating equivalent values is referred to as *discounting* if amounts are brought back in time; it is referred to as *compounding* if amounts are moved forward into the future. These techniques may be applied to both single amounts and annuities. An *annuity* is a series of equal payments made at regular intervals.

The following relations are used in computing equivalent values of money. Some nomenclature:

- i : the interest rate per period, or the discount rate.
- N : the number of interest or discounting periods.
- P : a “present” amount of money.
- F : a “future” amount of money at the end of N periods.
- A : an end-of-period payment (or receipt) in a uniform series of payments (or receipts) over N periods at i interest or discount rate.

It is common convention to assume that

- all capital investments or expenses occur at the beginning of the year, and
- all fixed and variable costs associated with capital investments occur at the end of the year.
- annuity payments are assumed to occur at the end of each time period (as previously mentioned).

Single Amounts moved in time:

The present worth factor (PWF) is used to determine the equivalent present value of a future expenditure:

$$P = F \times \text{PWF} = F \times \frac{1}{(1+i)^N} \quad (2)$$

The compound amount factor (CAF) is used to determine the equivalent future value of a present expenditure:

$$F = P \times \text{CAF} = P \times (1+i)^N \quad (3)$$

Figure 1 illustrates these two calculations.

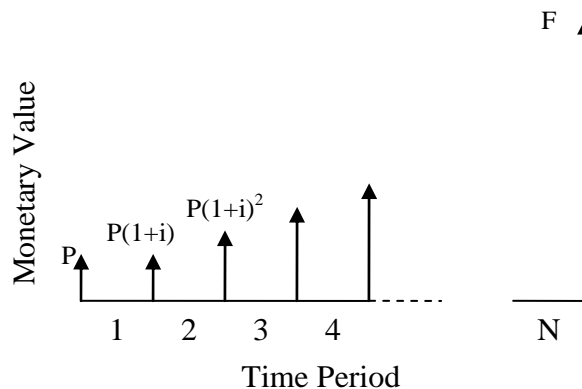


Fig. 1: Cash Flow Diagram for Present and Future Values

Annuities to single amounts:

The **series present worth factor (SPWF)** is used to determine the equivalent present value of a series of equal payments (an annuity):

$$P = A \times \text{SPWF} = A \times \frac{(1+i)^N - 1}{i(1+i)^N} \tag{4}$$

The **series compound amount factor (SCAF)** is used to determine the equivalent future value of a series of equal payments (an annuity):

$$F = A \times \text{SCAF} = A \times \frac{(1+i)^N - 1}{i} \tag{5}$$

Figure 2 illustrates these two calculations. Note that payment A is made at the end of a period, so there is no payment made at the beginning of period 1, but there is a payment made at the end of period N . It is easy to use (4) and (5) to show that P and F are related to each other via (2) and (3).

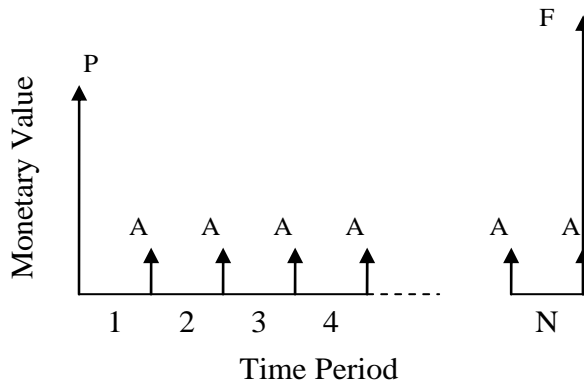


Fig. 2: Cash flow diagram for a uniform series of payments

Single amounts to annuities:

The **sinking fund factor (SFF)** is used to determine the annuity that is equivalent to a future expenditure:

$$A = F \times \text{SFF} = F \times \frac{i}{(1+i)^N - 1} \quad (6)$$

This is used, for example, when we want to save an amount, F , at year N by saving $\$A/\text{year}$ at interest i .

The capital recovery factor (CRF) is used to determine the annuity that is equivalent to a present expenditure:

$$A = P \times \text{CRF} = P \times \frac{i(1+i)^N}{(1+i)^N - 1} \quad (7)$$

This is used, for example, when we owe a present debt P that we want to zero at year N by paying $\$A/\text{year}$ at interest i .

Example: An electric utility finances $\$9,426,914$ to build a 25 mile-long transmission line at an annual rate of 10%. What is the annual payment necessary for repayment at 30 years?

Answer: This is a capital recovery problem, with $N=30$, $i=0.1$, and $P=\$9,426,914$. From (7), we have

$$\begin{aligned} A &= P \times \frac{i(1+i)^N}{(1+i)^N - 1} \\ &= 9426914 \times \frac{0.1(1+0.1)^{30}}{(1+0.1)^{30} - 1} = 9426914 \times 0.1061 = 1,000,000 \end{aligned}$$

Some interesting questions:

1. How much of year 1 is interest; how much reduces the principal?

$$\rightarrow \text{Interest} = 0.1 * 9,426,914 = \$942,691.4$$

So $1000000 - 942,691.4 = \$57,309$ reduces the principal.

2. How much of year 2 is interest; how much reduces the principal?

➔ The new principal is $9,426,914 - 57,309 = 9,369,605$

Interest = $0.1 * 9,369,605 = \$936,960.5$

So $1000000 - 936,960.5 = \$63,040$ reduces the principal.

Proceeding in this fashion, we may obtain the amount of each year's million dollar payment that is interest and the amount that reduces the principal. Figure 4 illustrates [3].

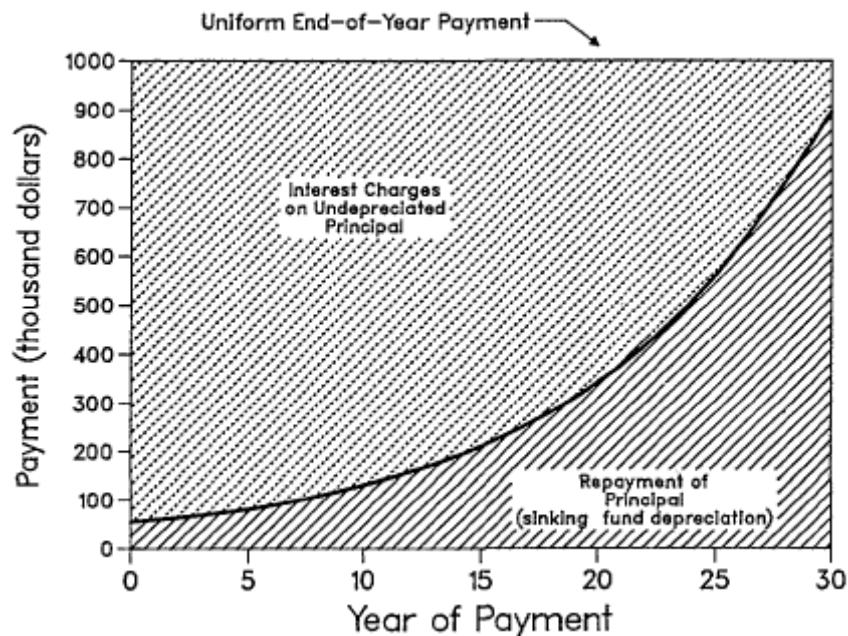


Fig. 4: Illustration of each year's interest and principal

5.0 Economic evaluation methods

It is important to recognize the difference between planning within

- a competitive business enterprise and
- an organization where rate of return on the rate-base is fixed by regulators.

In a competitive business enterprise, the most widely used economic evaluation method is called a “discounted cash-flow rate of return method.” In this method, the expectation is that future cash flows will provide a return on the original investment. Therefore, for each alternative,

1. Future cash flows are examined through the time horizon of the evaluation. These cash flows do not include the initial investment. It is assumed that
2. The discount rate is identified which results in future cash flows equaling the initial investment. This rate is called the “discounted cash-flow rate of return.”
3. All projects that have a discounted cash-flow rate of return that exceeds the cost of money are considered worth-while projects. The project with the highest discounted cash-flow rate of return is considered the best project.

In contrast, as we have seen, a regulated organization has its rate of return that can be provided to common stockholders fixed by the regulator agency. As a result, the “discounted cash-flow rate of return method, which compares different alternatives based on a computed rate of return, should not be used. Rather, methods which compare different alternatives based on a computed equivalent cost, for a fixed rate of return, make more sense.

The most common approach for economic evaluation of alternatives used by utilities is called the *revenue requirements method*.

Revenue requirements consist of two items: the annual fixed charges on a new investment and the annual expenses for fuel, operation, and maintenance. Calculations are made using the formula accounting for time value of money, to enable proper comparison between the alternatives.

One approach is to discount all costs associated with a project, present & future, to a specific point in time, usually the beginning of the study period. Then the present value of the costs for one alternative can be directly compared with the present value of the costs for the other alternatives.

One disadvantage of this approach is that the present value of all costs for an alternative can be quite large. To help make the total cost for an alternative easier to comprehend and to give the analyst a better feel for the annual differences between alternatives, the costs can be expressed on an equivalent annual cost basis.

Equivalent annual costs, also called level annual costs, represent the annuity which is exactly equivalent to all the costs incurred in an alternative. One method of making this calculation is to first determine the present value of all costs for an alternative (at the beginning of the study period), and then multiple this present value by the capital recovery factor for the length of the study period to “levelize” the costs over the study period

These costs are sometimes referred to as the levelized annual revenue requirements (LARR).

It is important to understand the distinction between LARR and actual revenue requirements. Since actual revenue requirements are seldom constant each year over the life of a project, it is difficult to compare actual revenue requirements between alternative projects. Thus, LARR represents the annuity that is equivalent to the actual revenues the company should receive.

Example:

Consider three power plants having the below data. One is a pulverized coal power plant, one is a combined cycle plant, and one is a nuclear plant.

Data	PC plant	NGCC plant	Nuclear plant
Overnight cost	\$1600/kW	\$850	\$2300/kW
Levelized fixed charge rate	20%	20%	20%
Plant rating	1000 MW	1000 MW	1000 MW
Full-load heat rate	9.6 MBTU/MWh	7.2 MBTU/MWh	9.3 MBTU/MWh
2010 fuel price	\$1.75/MBTU (coal)	\$8.00/MBTU (gas)	\$0.85/MBTU (uranium)
Fuel price inflation	1%/year	2%/year	1%/year
Capacity factor	1.0	1.0	1.0
Discount rate	8%	8%	8%

Compute and plot

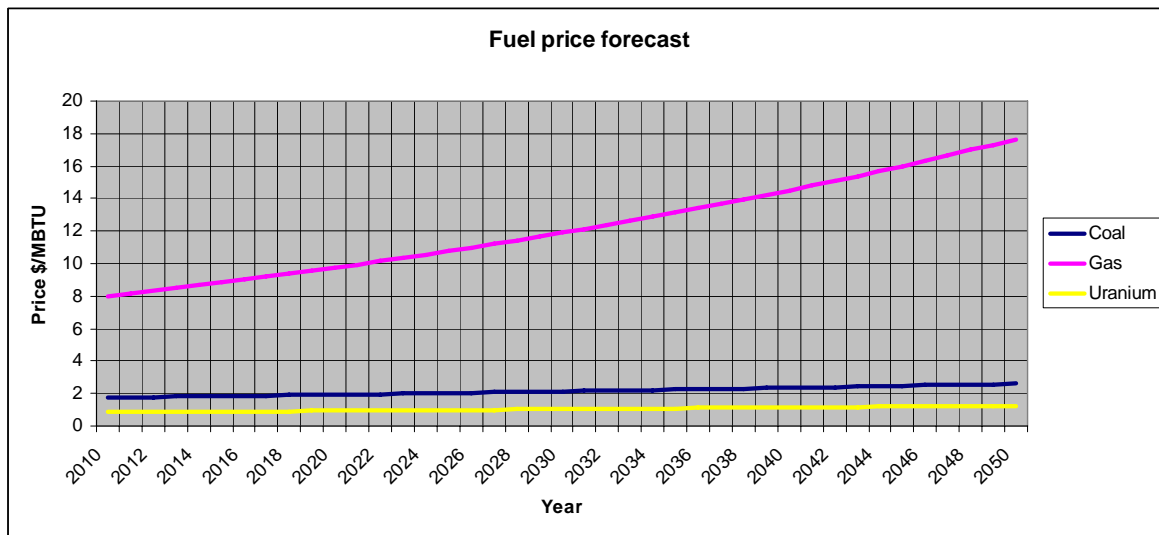
1. the fuel price forecast for the three fuels, assuming the initial 2010 fuel price and the fuel price inflation,
2. the operational cost for the three plants, assuming they operate at the given capacity factor 8760 hrs/year,
3. the annual fixed charges for the three plants, assuming the given levelized fixed charge rate, and
4. the total annual costs for the three plants

Also compute

5. the present value of the investment plus operating cost,
6. the levelized value of the investment plus operating cost.

Solution:

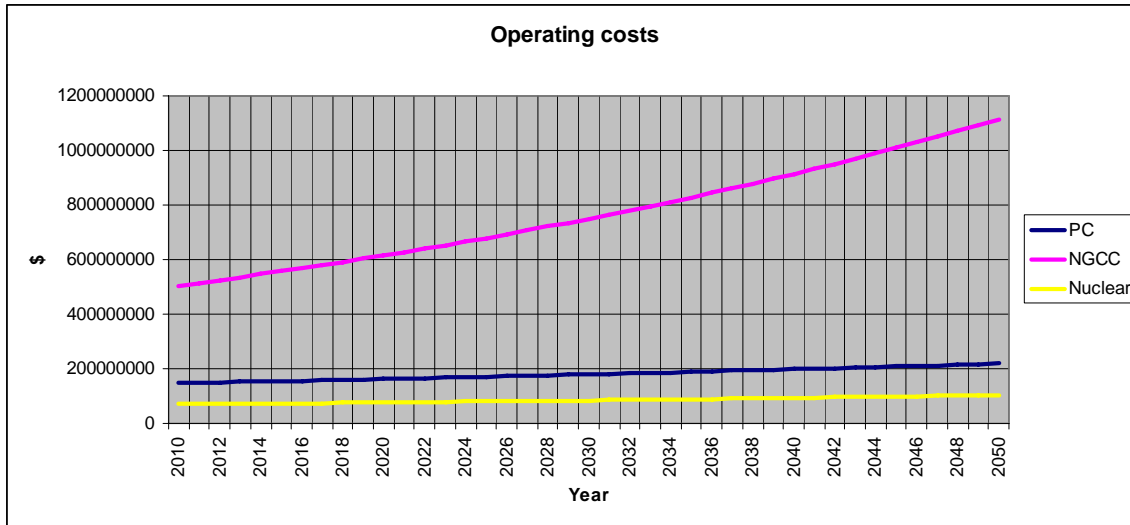
1. Fuel price forecast:



2. Operational cost for the three plants:

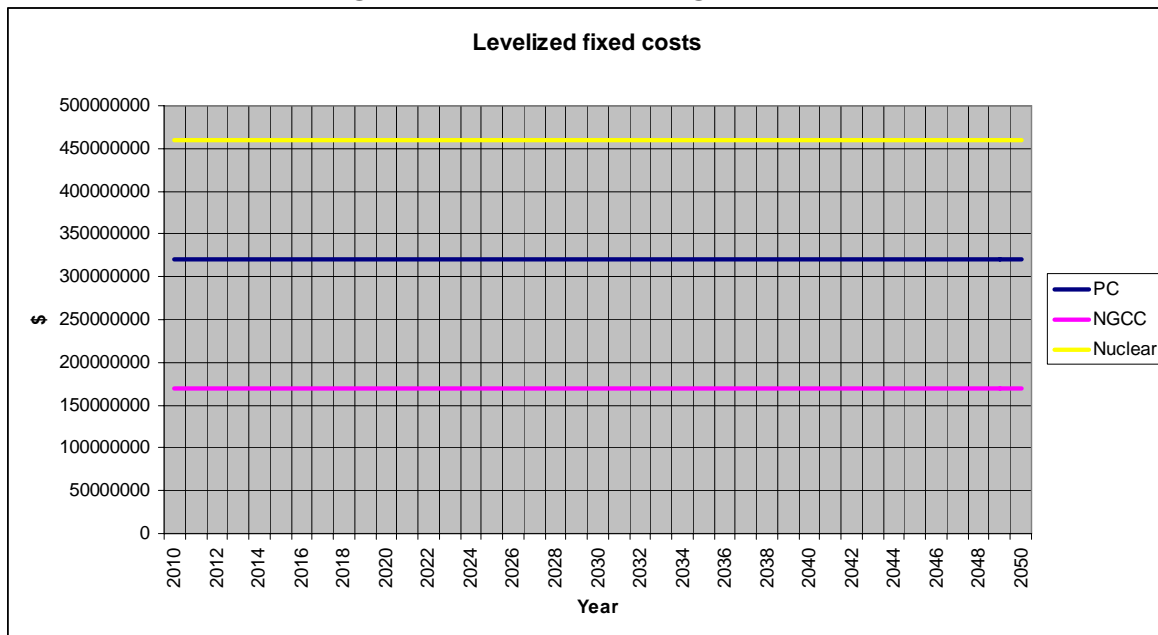
→ This is obtained from:

$$\begin{aligned} \text{OpCost}(t) &= \text{Cap} * \text{Capfactor} * 8760 * \text{Heatrate} * \text{Fuelprice}(t) \\ &= 1000 * 1 * 8760 * \text{Heatrate} * \text{Fuelprice}(t) \end{aligned}$$



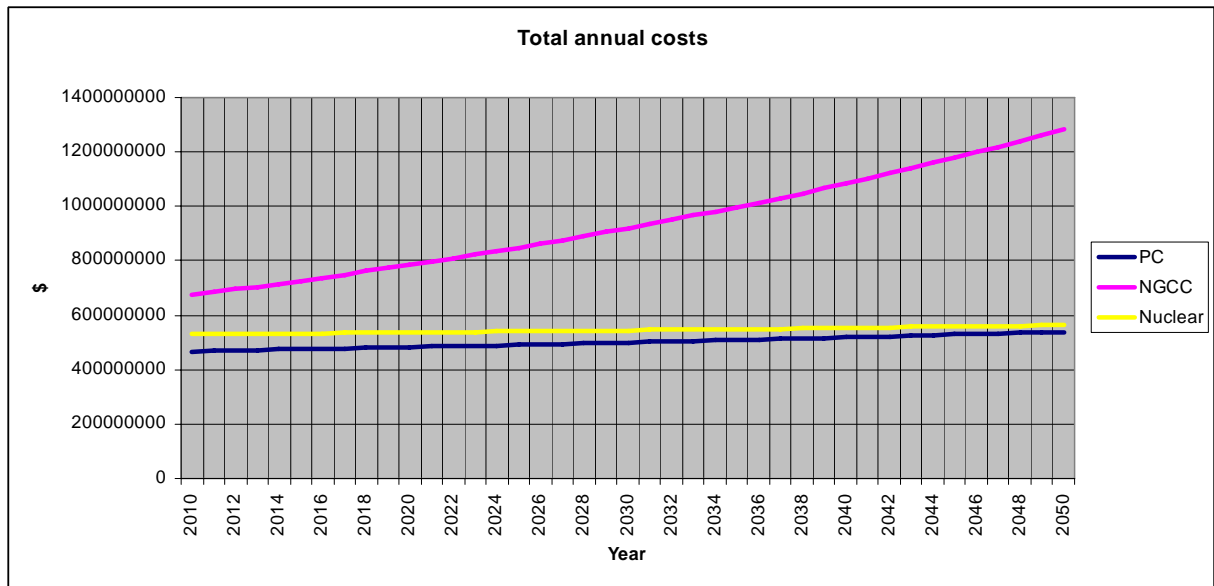
3. Annual fixed charges are straightforward, since we are given the levelized fixed charge rate.

$$\rightarrow \text{FixedCharges}(t) = \text{FixedChargeRate} * \text{Investment}$$



4. Total annual costs of the plants

$$\text{TotalCost}(t) = \text{OpCost}(t) + \text{FixedCharges}(t)$$



5. The present values

This is computed by finding the present worth of each year's total cost and then summing all of the present worth's, i.e.,

$$P = \sum_{t=0}^{40} \text{TotalCost}(t) \times \frac{1}{(1+i)^t}$$

where $i=8\%$. The result is:

PC	NGCC	Nuclear
6,260,941,978	10,407,721,559	6,945,241,446

\$6.26 billion for the coal plant,
 \$10.4 billion for the combined cycle, and
 \$6.94 billion for the nuclear plant.

6. The levelized value (LARR)

This is computed from the present worth using the capital recovery factor, eq. (7):

$$A = P \times \text{CRF} = P \times \frac{i(1+i)^N}{(1+i)^N - 1}$$

with $i=8\%$ and P as given in #5 above. Results are:

PC	NGCC	Nuclear
525,043,605.4	872,793,210.8	582,429,069.3

\$525 million/year for the coal plant

\$873 million/year for the combined cycle plant and

\$582 million/year for the nuclear plant.....

6.0 Economic analysis steps

Each economic analysis is different, but there are some common steps, as follows:

1. State objective
2. Define alternatives: Include the “do-nothing” alternative. Each admitted alternative should (a) be feasible and (b) accomplish the objective.
3. Identify incremental costs of each alternative: These are the costs that are not incurred with all alternatives. Costs that will be incurred in the future and are common to all the alternatives are of no significance since they will occur regardless of which alternative course of action is chosen. Similarly, costs that have occurred in the past are usually irrelevant in the

economic analysis because no future course of action can change the fact that these costs have already been incurred.

4. Choose study period: The study period represents that period of time over which costs are analyzed. The study period must extend far enough into the future to include all incremental costs for the alternatives being analyzed.

One interesting difficulty often arises in the above type of analysis that requires further discussion here.

Since alternatives are compared on the basis of total project cost, the alternatives must be defined so that they provide

- equal service (output, capacity)
- for equal lengths of time.

Otherwise, an alternative providing less service, or the same service for less time, may appear to result in lower costs and therefore might be chosen as the best alternative when in fact this alternative may result in greater total costs to the customers than one or more other alternatives.

6.1 Choosing study period

Two methods for choosing the study period that address the possibility that different alternatives may have different service times are as follows:

1. Salvage value approach: In this approach, the study period is set equal to the estimated service life of the alternative with the shortest service life. Then we assign salvage values at the end of the study period for those alternatives that have service lives greater than the study period. These

salvage values should reflect the value of the lost service over the remaining service lives of the alternatives due to the hypothetical early retirement of these facilities.

2. Additional service approach: In this approach, the study period is set equal to the estimated service life of the alternative with the longest service life. Then we assign additional service from another source for the alternatives with service lives less than the study period.

Example: A new power plant is required to meet future electric load. There are two alternatives:

Alternative A:

Service life=30 years

Capacity=100 MW

Alternative B:

Service life=20 years

Capacity=100 MW

- Approach 1: Choose a 20 year study period with salvage value for Alternative A:
- Approach 2: Choose a 30 year period assuming you will establish a 10 year contract to buy firm power from a neighboring generation owner for the last decade.

6.2 Equalizing service provided

Here, one must provide for service from another source if alternatives do not have the same output per year. That is, if two alternatives differ in service for some years, the cost of obtaining service elsewhere should be included as a cost to the alternative which provides less output.

Example: A new power plant is required to meet future electric load. There are two alternatives:

Alternative A:

Service life=20 years

Capacity=100 MW

Alternative B:

Service life=20 years

Capacity=50 MW

- Approach 1: Assume Alternative B is comprised of two 50 MW units, rather than one.
- Approach 2: Assume Alternative B must obtain a 20 year contract to buy firm power from a neighboring generation owner over the life of the project.

[1] Manual of Engineering Economics, second edition, Pacific Gas and Electric Company, 1986.

[2] H. Stoll, "Least-Cost Electric Utility Planning," Wiley, 1989.

[3] International Atomic Energy Agency, "Expansion planning for electrical generation systems," Technical Reports Series No 241, 1984.