Real Options Approach to Capacity Planning Under Uncertainty

by

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ABSTRACT

This thesis highlights the *effectiveness* of Real Options Analysis (ROA) in capacity planning decisions for engineering projects subject to uncertainty. This is in contrast to the irreversible decision-making proposed by the *deterministic* strategies based on expected estimates of parameters drawn years in advance. *Effectiveness* is measured by three metrics: cost efficiency, capacity sufficiency and Value at Risk. The study documents the effects of uncertainty on planning facilities with high fixed-costs. It addresses engineers and planners by presenting fundamental insights of ROA without expecting Options-pricing knowledge a priori.

The main idea is demonstrated via a case study of hydropower capacity planning. An analytical *probabilistic* capacity planning tool is developed to compare results given by traditional valuation and ROA. The tool may be useful for determining resource utilization policies and decision-making in the construction of such plants. Two specific options have been examined: (1) Vary size and timing of capacity increment (2) Defer hydropower plant construction to observe demand by relying on low fixed-cost and high operational-cost facilities in the initial years. The conclusion is that dynamic capacity planning approach is more *effective* if the forecasts are pessimistic or optimistic but not necessarily if realized parameters are similar to forecasts. Decisions based on distribution of driving factors and outcomes may be better aligned with the management's overall risk preferences than those based solely on expected mean of these parameters.

Thesis Supervisor: Richard de Neufville
Title: Professor of Engineering Systems and of Civil and Environmental Engineering

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1 Introduction

"The only certainty is that nothing is certain"

-- Roman scholar Pliny the Elder

Webster dictionary defines *uncertainty* as the lack of conviction or knowledge especially about an outcome.

This study addresses whether Real Options Analysis (ROA) approach to evaluation of capital investment strategies in engineering projects faced with uncertainty is more *effective* than traditional *deterministic* approaches. Traditionally capital budgeting decision-making is *static;* it is irreversible (all decisions are assumed unchangeable throughout the lifetime of project), inflexible (assumes all the sequential decisions in advance) and deterministic (cash flows are based on the *expected* outcomes instead of the *distribution* of possible outcomes). It is supported by *deterministic* valuation methods based on expected values of governing parameters drawn years in advance. Examples of such methods include Cost Benefit analysis (CBA), Net Present Value (NPV) or Internal Rate of Return (IRR). Expected average of uncertain quantities does not capture all the information about their distribution, so it may not be the right metric for decision-making. Conventional valuations are acceptable if expected outcomes prevail, but they prove inaccurate if the outcomes are vastly different from prior expectations.

ROA is not just a valuation methodology; it is a unique paradigm for planning and decision-making from a systems dynamics or capital budgeting perspective. It allows the management to manage *systematic risk* arising from future uncertainty so that the decision-making is aligned with their risk preferences. A capital budgeting strategy based on ROA incorporates flexibility in decision-making or system design so that the project responds most *efficiently* to various possible outcomes.

Effectiveness of ROA over conventional methodologies is compared by 3 metrics:

1. ***Cost efficiency***: Most cost-efficient use of resources
2. ***Capacity sufficiency***: System meets demand at all times without relying on external sources
3. ***Value at Risk***: Measurement of systematic risk

The methodological and analytical pillars of ROA rest on the foundation of *Options Pricing Theory* (explained in Section 5.1) developed for valuation of financial *options*. An *option* is the right but not the obligation to make a certain decision. Options on real assets like land, manufacturing facilities, mines etc. as opposed to financial assets like stock, bond, stock indices etc. are called Real Options. ROA captures the intangible value of embedding flexibility in decision-making or system design for any project.

1.1 Case Study: Hydropower Capacity Planning

The typical facilities studied in this thesis are large engineering and manufacturing plants which require significant upfront investments with long lead times for planning or construction and a few decades worth of design life. A case study of hydropower capacity planning shows the practical application of all the theoretical aspects of ROA explained in this thesis. Although various other types of facilities would suffice the purpose, findings by World Commission of Dams (WCD) document the need for a new paradigm in this sector.

The crux of this study is conveyed by weighing results obtained by traditional valuation and capacity planning methodologies vs. ROA-based approach. An analytical tool has been developed to simulate various demand scenarios and capacity increment to compute results from *static* and *deterministic* capacity installation (in accordance with conventional and ROA-based capacity planning approach).

Two main *options* have been explored:

1. ***Option to vary size and frequency of capacity increment***: Traditionally, assuming a constant rate of demand growth, the system capacity is augmented by the pre-determined *optimal* plant size in every n^{th} year. ROA proposes a flexible capacity increment strategy based on a distribution of demand and outcomes, rather than forecasts of mean demand solely. Thus having accounted for the demand uncertainty, the optimal plant size is computed (often different from that suggested by the conventional strategy) such that the planners have the *option* to vary the size and frequency of capacity increments.
2. ***Option to defer by operating oil-fired plants in the initial years***: It may be beneficial to wait and observe demand before making huge irreversible investments in hydropower plants based on demand forecasts only. ROA helps to weigh benefits of using alternate power sources with low installation cost and higher operational costs. This gives better understanding of demand patterns, leading to better judgment of *optimal* plant size and timing of construction. Decision-makers have the *option* to switch from alternate sources to hydropower anytime. Initially determined *optimal* plant size may be upsized or downsized if the forecasts are observed to be overly pessimistic or optimistic.

To establish the logic of argument, conventional financial feasibility and capacity planning methodologies are reviewed. A closer look at energy forecasts proves that in spite of sophisticated models and assumptions, forecasts are unreliable for long-term capacity planning. Current practices in hydropower capacity planning are proven to neglect the risk of future uncertainty (static approach). On the other hand, ROA accounts for this risk by way of proposing a flexible solution appropriate for a variety of outcomes (dynamic approach). The essence of content in this thesis is condensed into valuation of the 2 aforementioned *options* and proving the advantages of the ROA approach.

1.2 Organization of Thesis

This thesis is organized as follows:

- Chapter 2 introduces general financial and economic risks associated with dam construction and reviews well-know financial feasibility criteria.
- Chapter 3 establishes inaccuracy of energy forecasts. It includes relevant data, discussion on forecast preparation methodology and specific instances of imprecise forecasts.
- Chapter 4 illustrates deterministic practices in capacity planning and consequences of ignoring the risk of uncertainty.
- Chapter 5 initiates the fundamentals of ROA with the help of simple examples. A detailed example on capacity planning in tunnels paves way for the more complex hydropower capacity planning.
- Chapter 6 builds upon analytics of Chapter 5 and focuses on ROA-based hydropower capacity planning. After ascertaining the *effectiveness* of ROA over conventional planning techniques, the chapter concludes with evaluating the benefits of the 2 aforementioned *options*.
- Chapter 7 distills the important conclusions of this study..

2 Construction of Dams

This chapter examines the financial and economic risks owed to uncertainty in planning and construction of large dams. It is divided in four sections. The first section summarizes a few facts about large dams and hydropower energy. The second section establishes the need for a change in the decision-making paradigm in hydropower capacity planning. The third section reviews inherent economic and financial risks and the fourth section outlines a few traditional valuation methods.

2.1 Facts about Large Dams and Hydropower Energy

Dams have been built since centuries for managing floods, generation of hydropower energy, water supply, irrigation of fields etc. According to the International Commission on Large Dams (ICOLD), a large dam is defined as either having a height of 15 m or more (from the foundation) or 5-15 m with reservoir volume greater than 3 million cubic meters. Using this definition, at least 45,000 large dams have been built till the year 2000 to meet the energy or water requirements [WCD 2000]. The top-five dam building countries[1] account for more than-quarters of all large dams internationally. At the beginning of this century, hydropower contributed to more than half the energy in approximately one-third of the counties in the world. Large dams generated about 19% of the overall energy in the world. In fact, hydropower accounts for more than 90% of total electricity supply in 24 countries such as Brazil, Iceland and Norway. Last century witnessed a proliferation of large dams. In the 1930's and 1970's, the construction of large dams was considered synonymous with modernization, development and economic progress.

[1] Top five dam building countries are: China, United States, India, Spain and Japan [WCD 2000]

2.2 Need for New Paradigm in Hydropower Capacity Planning

It is only in the last 50 years that the economic, financial, social and environmental impact of the large dams has come under international scrutiny and public debate. Planners and economists have expressed the need for a changed approach towards capacity planning of large-scale energy-projects [WCD 2000]. Proposals to construct large dams are being actively contested in the name of sustainable development, to the point that their future is questionable: Narmada Valley Dam in India, Karahnjukar Project in Iceland and Three Gorges Project in China are just a few examples.

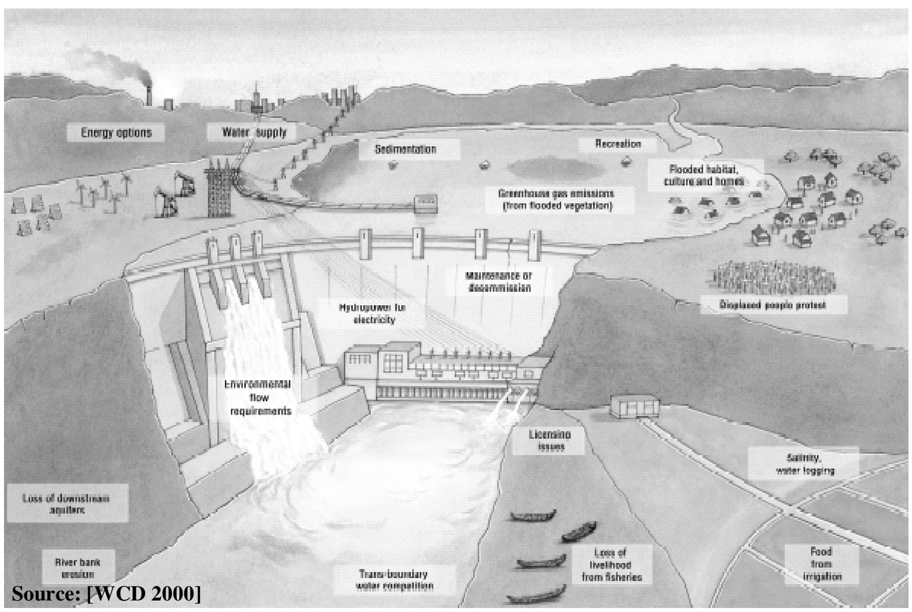


Figure 2.1: Costs and Benefits of Large Dams

Purveyors of large dams advocate the economic, social and environmental benefits. The opponents protest against adverse impacts such as enormous debts, cost overruns, construction delays, displacement of people, imbalance of ecosystem and fisheries, inequitable demand & supply situation in the hydropower sector, loss of silting benefits etc. Figure 2.1 indicates some benefits and costs associated with the construction of large dams.

WCD [2000] documents numerous examples of hydropower projects that logged financial losses due to inappropriate risk accounting measures. Typically, losses result due to system-wide or project specific risk of uncertainty: mismatch between installed capacity and realized demand, electricity price fluctuations, construction-delays, cost over-runs or curtailed project life. A new paradigm of planning and decision-making which addresses financial and economic risks more effectively is the need of the hour.

2.3 Financial and Economic Risks

2.3.1 Overview

According to the WCD [2000], financial feasibility studies of large dams fail to account suitably for the risks and uncertainties associated with estimates of project costs and benefits, project life, discount rates etc. Little effort has been made to date to conduct *options* or scenario-based analysis of joint effects of uncertainty and irreversibility of decision-making. The planning approach has been *deterministic*, taking a stationary view of important variables such as energy demand, oil prices, new sources of energy, capacity expansion of existing sources etc. Although these variables and assumptions driving financial feasibility are ridden with uncertainty, they are treated as though known with *certainty*.

2.3.2 Examples of Financial Failure in Hydropower Capacity Planning

WCD [2000] cross-survey of 77 large dams across the world shows a high variability in hydropower performance; excess or deficient capacity installation vis-à-vis the requirement at the time these facilities are commissioned. Capacity excess is more common than deficit. Results of the survey (Figure 2.2) signify that approximately half the plants exceeded estimated targets of power generation: about 15% exceeded the targets by large amounts.

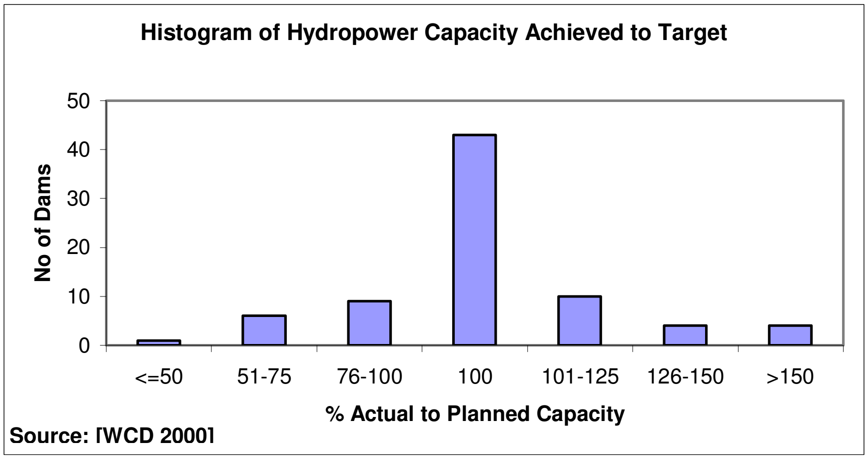


Figure 2.2: Histogram of Hydropower Capacity Achieved to Target

On the other hand, about 20% projects in the sample achieved less than 75% of planned power generation. The following examples corroborate the mismatch between installed capacity and materialized demand.

2.3.2.1 Example A: Grand Coulee Dam (GCD)

Installed capacity at GCD far exceeded the electricity demand at the time the dam was commissioned. Fortunately the demand had escalated due to unforeseen reasons to absorb a portion of the excess capacity. The planners had failed to anticipate a change in the demand pattern. Huge cost over-runs suggested errors in cost-benefit estimates [WCD 2000].

Till 2000, GCD was the largest producer of electricity in USA and third largest producer of electricity in the world[2]. In 1932 construction of Grand Coulee Dam on Grand Coulee Canyon was meant to provide cheap hydropower. GCD was constructed in

[2] Currently the newly constructed 3 Gorges Dam in China is the largest producer of electricity.

two phases from 1933 to 1941 and mid 1960's to 1975. Table 2.1 lists the vast difference between estimated and actual costs at both stages of construction.

Table 2.1: Estimated vs. Actual Construction Cost for Grand Coulee Dam

	Year Completed	Construction Costs		
		Estimated	Actual	% Difference
Stage I	1941	2.0	2.6	30
Stage II	1975	1.9	2.9	53

Source: [WCD 2000] Cost in $1988 billion

Even before the dam was commissioned, there were wide spread concerns that demand worth 800,000 KW of continuous firm power will not materialize within forecasted time.

Fortuitously, from 1949 onwards, low power rates, high demand for aluminum and population growth led to an escalation of power demand in that area. Though planners did not account for these factors at the time of construction, some of the excess power supply was absorbed by war-related economic growth that fueled industrial expansion in the area. Though power supply was already in excess of demand, with second stage construction[3] completion in 1975, installed capacity grossly exceeded the 1932 estimates. The installed capacity continued to exceed actual demand for a longer duration than initial forecasts.

2.3.2.2 Example B: Excess Electricity Capacity in South Africa

Excess electricity capacity on the South African interconnected grid is another example of divergence between installed capacity and actual demand [Aberdein 1994]. Figure 2.3 charts escalation of excess capacity on the Eskom Grid from the early 80's. It was arguably attributed to unforeseen changes in growth of electricity demand in conjunction with the policy to build large power stations far in advance of actual demand.

[3] Second stage construction entailed installing a third power plant that was never planned in the 1932 design.

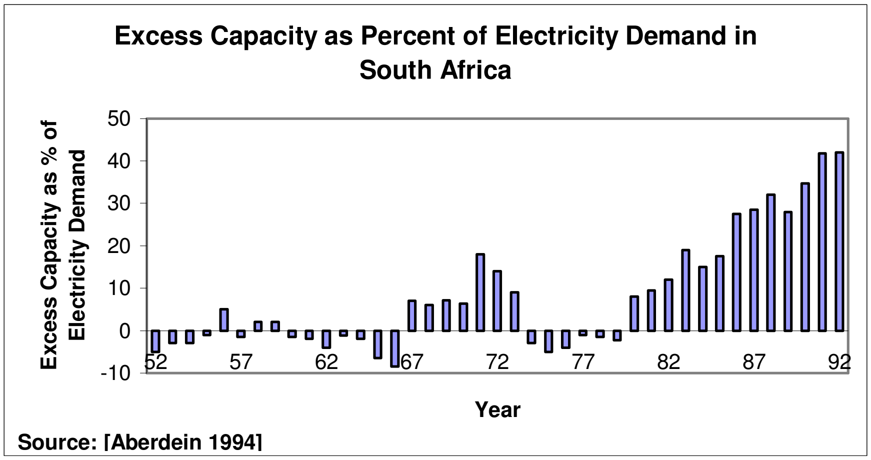


Figure 2.3: Excess Capacity as Percent of Electricity Demand in South Africa

Such plants reduce flexibility of the planning process since they necessitate the utilities to enter in contracts with suppliers for construction periods of up to 10 years or longer, regardless of the demand situation.

2.4 Traditional Financial Feasibility Criteria

Financial Feasibility is the overall determination of whether the tangible value of project output will be sufficient to account for financial obligations such as amortization of loans, operation and maintenance costs, interest payments and other such costs. Present and future cash flows of the project are a good measure for determining financial feasibility of the project. [Fritz 1984]. These are a few prominent criteria dictating capital budgeting decisions in capacity planning.

2.4.1 Net Present Value

Net Present Value (NPV) is one of the oldest and best-known methods to rank financial feasibility of projects. It is also known as Discounted Cash Flow (DCF) method. For calculating the NPV, the annual difference between project benefits and costs is discounted back to the time at which NPV is being calculated and cumulatively added to a single sum. The least NPV alternative is favored.

Table 2.2: Disadvantages of NPV

Disadvantages of NPV or DCF: Assumption vs. Reality	
NPV Assumption	**Realities**
Decisions are made now and cash flow streams are fixed for future.	Uncertainty and variability in future outcomes. Not all decisions are made today, as some may deferred to the future, when uncertainty resolves.
Once launched, all projects are passively managed.	Projects are usually actively managed throughout the project life-cycle, including check-points, decision options, budget constraints etc.
Future free cash flow streams are all highly predicatable and deterministic.	It may be difficult to estimate future cash flows as they are usually stochastic and risky in nature.
Project discount rate used is the opportunity cost of capital, which is proportional to non-diversifiable risk.	There are multiple sources of business risk with different characteristics, and some are diversifiable across projects or time.
All risks are completely accounted for by the constant discount rate.	Project risk can change during the course of time.
All factors that could affect the outcome of the project are reflected in NPV.	Project complexity and so-called externalities make it difficult to quantify all factors in terms of incremental cash flows. Disrupted, unplanned outcomes can be significant and strategically important
Unknown, intangible or immesuarable factors are valued at zero.	Many important benefits may be intangible assets or qualitative strategic positions.

Adapted from Mun [2002]

This technique is mathematically and computationally simple but most importantly reduces financial and economic information about the project to a single value for the ease of decision-making. Table 2.2 summarizes some disadvantages of NPV by contrasting assumptions and realities. The fundamental flaw with NPV method is that it does not incorporate the risk of uncertainty by treating future cash flows in a deterministic manner. There is no definitive way to decide the discount rate to be used, so it is subject to question. Also NPV yields no information about the ratio of costs to benefits.

2.4.2 Internal Rate of Return

Internal Rate of Return (IRR) is that discount rate at which the net present value of the project is zero. Projects with an IRR higher (lower) than opportunity costs are accepted (rejected). The merit of this method is that it allows planners to determine financial feasibility of projects without having to choose a rate of discount as in DCF or NPV. The method has computational advantages when choosing between multiple projects with similar objectives. Apart from this, IRR suffers from all the flaws formerly noted in NPV (See Table 2.2).

2.4.3 Life Cycle Costs

Life cycle costing (LCC) is a variation of DCF or NPV methods. LCC has gained popularity due to current interest in comparing projects with different cost profiles such as high front-end capital costs vs. high operational costs. So this method is particularly useful for comparing the financial attractiveness of hydropower plants against thermal plants [Fritz 1984]. LCC of an energy system is the present value sum of all the costs related to capital, operation, debt service and maintenance over the *entire* project life. For instance if the life of a hydropower plant is equivalent to three diesel plant lives, a trade-off situation exists. After a certain period a break-even point is reached where low capital cost and high accumulated cost of diesel is equivalent to the high initial and low accumulated cost of the hydropower plant. Beyond this trade-off point, hydropower plant appears more attractive. The main point of difference is that in traditional NPV, decision-makers would account for cash flows over the life of a thermal and hydropower plant for a time period equal to the lesser of two design lives. Thermal plants have smaller design lives and hydropower plants have no salvage value, so hydropower plant might not prove to be an attractive alternative from such a perspective. Like NPV and IRR, this method also disregards the risk of future uncertainty (See Table 2.2).

2.4.4 Cost Benefit Analysis as Decision Making Tool

Since the 70's, Cost Benefit Analysis[4] (CBA) has been the dominant decision support system adopted for economic and financial decision-making process involving large dams [WCD 2000]. CBA estimates equivalent economic worth of a project costs and benefits to determine financial and economic feasibility [Fuquitt 1999].

A common measure for expressing costs and benefits is chosen. The most convenient common unit is *money*. The monetary value of costs and benefits must be expressed in currency value at a particular time to account for *time value of money* and inflation. *Time value of money* implies that a dollar spent today is not equivalent to a dollar spent in the future. So the net benefit of the projects is sum of present value of benefits less the present value of costs. The choice of discounting factor is not easy to justify. The most challenging aspect of CBA is quantifying all the intangible costs and benefits. The problem is three-pronged.

1. *All variables are not readily quantifiable*: For instance displaced people have been known to suffer economic and cultural impoverishment, higher rate of sickness, malnutrition and deaths but these costs are not readily quantifiable [Morimoto 2001].
2. *All costs and benefits can not be anticipated:* For instance the construction of Aswan High Dam led to change in the climatic pattern and silting of the downstream plains, thus affecting irrigation. These costs were completely unanticipated in the original CBA conducted by the Egyptian government [Shibl 1971].

[4] Also known as Benefit Cost Analysis or Cost Benefit Ratio Analysis. This is a family of methods which account for benefits and costs separately.

3. *Future uncertainty cannot be accounted for accurately*: The estimated costs and benefits may change significantly. For instance the present cost of constructing Narmada Valley Dam (India) is 8 times the initial estimates. Though construction delays are accounted for, the prolonged delay due to public protests surpassed expectations [WCD 2000].

Henceforth, the estimated costs (benefits) are higher (lower) than actual costs (benefits).

2.4.5 Probabilistic Cost Benefit Analysis

All the methods presented so far disregard the risk of uncertainty. Morimoto and Hope's [2002] empirical work on dams in Malaysia (Bakun Dam), Nepal (Sharada Babai Dam) and Turkey (Ilisu Dam) tackles uncertainty by way of probabilistic CBA. They use probabilistic distributions for input parameters in CBA model and analyze the financial implications of constructing the proposed dams.[5] They examined correlation between capacity, construction cost, construction period and the effects of decommissioning.[6] Their analysis reveals potential outcomes of constructing these proposed projects. Using probabilistic distribution for input parameters allows them to compute a distribution of NPV. This captures more information about project feasibility than a single NPV value that is computed using the expected mean of input parameters. They have also examined the option to decommission dams and contingent effects on cumulative NPV.

For instance in Bakun Dam, the 5th percentile, mean and 95th percentile of cumulative NPV are $-9.9, -2.9 and 7.0 billion (Figure 2.4). The cumulative NPV values show an improvement ($-9.6, $-2.8, $7.0 billion) if the dam was prematurely

[5] They consider minimum, most likely and maximum values for each input parameter. For example these values for total construction cost for Bakun Dam are (0.7, 0.8, 32 B$).
[6] The premature decommissioning option allows the dam to be closed early if the annual revenue drops below the annual unavoidable costs.

decommissioned. It impacts the 5th percentile value the most because chances of premature commissioning are most when the dam performs the worst. There is no change in the 95th percentile value because if the dam is performing extremely well then there is no need for premature decommissioning.

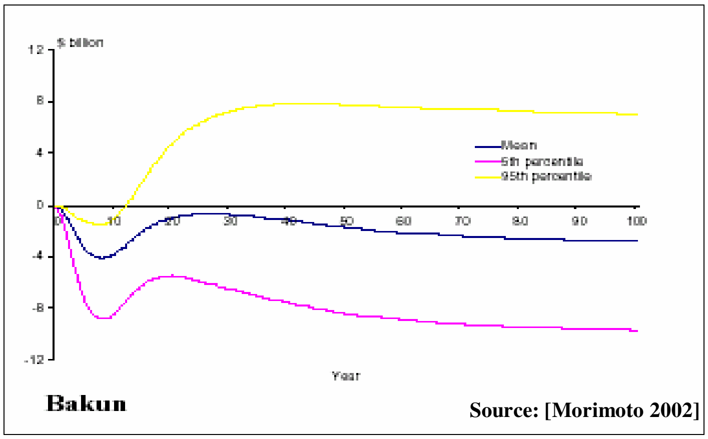


Figure 2.4: Range of Cumulative NPV for Bakun Dam

As shown above, the initial cumulative NPV values are strongly negative due to huge construction costs. The NPV mean and 5th percentile is negative for the entire duration of the project. Viewed from NPV perspective, the negative mean disfavors this project. However the 95th percentile is sufficiently positive, hinting at favorable outcomes. This is how probabilistic CBA presents detailed information on project risk and gives managers the flexibility to choose the project based on their risk preferences. In addition, it is a partially reversible decision, since decision-makers have the *option* to decommission the dam in the worse case situation.

2.4.6 Decision Tree Analysis

Decision Tree Analysis (DTA) is a useful tool for strategic decision-making because it accounts for uncertainty and managerial flexibility [de Neufville 1990]. DTA allows management to structure the decision problem by mapping all the feasible consequences contingent on possible *states of nature* (probabilistic events) in a hierarchical manner. The probabilities of occurrence of mutually exclusive events are derived from empirical data or domain knowledge. DTA is particularly useful in instances of layered uncertainty involving sequential investments when ambiguity is resolved at distinct, discrete points in time. DTA forces the management to realize interdependencies between sequential decisions and feasible operating strategy as opposed to NPV analysis focused on the initial accept or reject decisions while disregarding the contingent future decisions.

A decision tree has 2 kinds of nodes (decision points): *Decision nodes (squares)* represent separate decision points for *management*. They are connected via paths to *Outcome nodes (circles)*, which represent points in time when outcomes beyond the control of management are disclosed by nature. The decision-making is based on the concept of *dynamic programming.* A decision at the starting point of the tree can be *long-term optimal* only if all the sequential decisions are also optimal, therefore decision-making begins from the end (right hand side of the tree) and works backwards to the beginning. During this *rollback* procedure, the expected risk-adjusted NPV is calculated at each stage by multiplying NPV values of all consequent outcomes with their respective probabilities of occurrence.

Though DTA addresses some of the flaws observed in other valuation methods, its widespread application in industry is limited because:

1. In most realistic investment decisions, “decision tree” soon become “decision bush analysis” as the number of paths increase geometrically with the number of decisions, outcome variables and number of states considered for each variable. This makes it

analytically challenging, but worse it causes a loss of the intuition and clarity in outlining the optimal strategy.

2. For simplicity, at most two or three states are modeled for each outcome variable. In reality, the possible outcomes span a spectrum of values in between the chosen states. Also, uncertainty may resolve continuously and not necessarily at discrete points in time.
3. Choice of appropriate discount rate is subject to question. Using risk-adjusted discount rate to be constant in each year is incorrect. At every decision point, previous uncertainty is resolved and new risk is borne, which are not necessarily equal, therefore the same rate of discount can not be applied to all points in tree. If an *option* reduces the riskiness of the project, lower discount rate should be used. For instance the option to contract the project will decrease the riskiness of future cash flows as compared to initial cash flows but traditional DTA does not recognize reduction of risk by adjusting the discount rate.

3 Energy Forecasts

3.1 Introduction

This chapter questions the use and value of forecasts in energy capacity planning decision-making process by proving their uncertainty and unreliability. Forecasts are probable estimates of uncertain parameters based on historical trends. Chapters 2 and 4 emphasize the role of forecasts in *deterministic* capacity planning decision-making. The quality of decisions contingent on forecasts can only be as good as the quality of forecasts. An extensive study of U.S. energy forecasts corroborates the inaccuracy of forecasts. A look at forecasting assumptions and methodology verifies that the inaccuracy is not a function of forecasting agency, models, assumptions etc; intrinsic reason is that the future does not imitate the past and planners can not always anticipate changing trends precisely. All the discussion in this chapter is based on statistics and methodologies followed by Energy Information Administration, however the insights and conclusions are generic and hold true for forecasts in general.

Limited literature is available on the influence of uncertainty of forecasts in energy capacity planning. Lee et al [1998] have analyzed the risk of short-term power

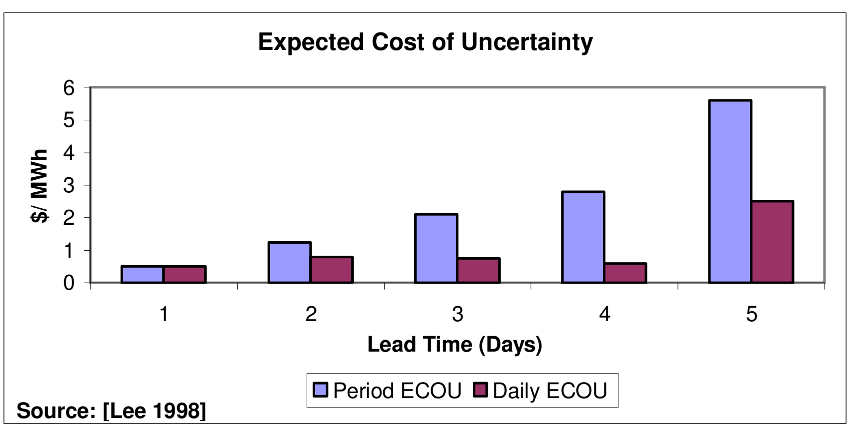


Figure 3.1: Expected Cost of Uncertainty as a Function of Lead Time

system operation planning in the presence of electrical load forecast uncertainty. They determine the risk due to load forecast variance by calculating the Expected Cost of Uncertainty (ECOU), also called the expected cost of perfect information using decision analysis. Figure 3.1 charts ECOU due to load forecast uncertainty as a function of forecast lead-time in the spring season. They conclude that ECOU spanning a quarter increases with lead-time, implying that ECOU is directly correlated to forecast uncertainty, both increasing with lead times.

3.2 Need for Energy Forecasts

Planning for a nation's energy needs is a difficult undertaking fraught with uncertainty. A typical electric utility plant takes 3-10 years to plan and construct and is expected to be operational over the next 30-40 years, so various variables need to be projected over the next 30-40 years from the time of planning. Although the case study in thesis deals with hydroelectricity, this discussion focuses on energy because it is an aggregated top-level concept.

The objective of energy forecasts is to facilitate construction of sufficient infrastructure for adequate energy supply by the most efficient means [Ascher 1978]. Energy *crises* occur frequently even when there is no actual shortfall of supply. Not all problems achieve the public status of *crises*. Often unforeseen energy demand does not disrupt regular activities by due to inefficient makeshift means of providing extra energy. For instance, in the Northeast America during the 80's, low efficiency power-gas turbine units satisfied unexpected demand, instead of the more efficient fossil fuel or nuclear plants. Utilities resorted to turbines because they could be installed more rapidly as compared to the conventional energy plants, which require longer lead times for planning and construction [EIA *Annual Energy Review* 1985].

Thus energy forecasts are a prerequisite for any aspect of providing energy that requires substantial 'lead times' for discovery, extraction, development or construction. The accuracy of overall energy demand forecasts is crucial:

1. Energy cannot be stored in advance for large-scale use.[7] In case of excess energy generation capacity, sufficient infrastructure might not be available to divert energy, forcing the utilities to operate at sub-optimal operation levels. In case of energy deficit, both residential and industrial consumers cannot be subjected to "light-outs"; makeshift arrangements to meet the shortage often prove costlier than sources providing regular supply.
2. Overall energy forecasts feed other forecasts segregated by source, sector, en-use etc. Any inaccuracy at the top-level forecasts is further compounded in the dependent forecasts.

3.3 Source of Data and Information

All the information and data in this chapter is sourced from the publications of Energy Information Administration (EIA). EIA provides the official energy statistics on behalf of the U.S. government and publishes periodic reports on the national and international status of energy and related fuels. Though various agencies in the oil and energy sector maintain databanks, differences in forecasting methodologies and assumptions results in minor information conflicts, so all the data is sourced from EIA only.

[7] Energy storage devices have been used to supply energy at a small scale for emergency purposes only because they are economically inefficient.

3.3.1 Data collection

All the information and data presented in this chapter is gathered from EIA publications dated up to late 80's. At the time this study was conducted, data was available from MIT Dewey Library for this period only. Later data for 90's was made available in Microfisch format. Forecasts drawn in 90's confirmed the generic conclusions and insights based on earlier forecasts. It was not deemed necessary to repeat the analysis in this chapter based on recent data to establish the same qualitative results conveyed by data from the 80's.

3.4 EIA Forecast Model

EIA uses a model called Intermediate Future Forecasting System (IFFS) for drawing year-to-year forecasts of all fuel interactions on a national basis over the period of next quarter to 20 years. IFFS is designed to track trends in energy markets and governing factors: variations in consumption and production of different fuels, fluctuation in oil prices, change in financial requirements of electric utilities etc. It incorporates an international and national view of both energy and fuel markets. Although it accounts for new technologies, it emphasizes on major fuels such as oil, coal and natural gas.

3.5 EIA Forecast Assumptions

An initiation into the intricate forecast assumptions and methodologies reveals why forecasts are inherently inaccurate. Energy forecasts are highly dependent on macroeconomic and microeconomic factors such as Gross Domestic Product (GDP) growth, population growth, oil prices, supply of other major fuels, introduction of new energy-generating technology etc. [EIA *Annual Energy Overview* 1981]. EIA recognizes the uncertainty in long-term planning by preparing multiple projections based on different scenarios of economic growth and underlying parameters. For instance, EIA assumes three scenarios of GDP growth: low, average and high. Based on historical trends, energy requirements in all the three economic scenarios are projected separately (*Low Case*, *Base Case*, *High Case* correspondingly). In spite of sophisticated models and scientific methods, the *past* and anticipated changes are not sufficient to predict the *future* accurately. Table 3.1 shows the changing trends in GDP growth and net electricity generation growth in U.S. from 1960 to 1990. In early 70's, planners did not expect that growth rate of electricity demand and generation would decline over the next two decades. This amounted to general under-utilization of electric utilities in early 70's.

Table 3.1: Annualized % Growth of Net Electricity Generation and GDP in U.S.

Time	Electricity	GDP
1960-1970	10.2	3.8
1970-1980	4.9	2.8
1980-1990	3.2	2.6
1990-2000	2.5	3.1

Source: [EIA *Annual Energy Review* 2001]

Coal-fired plants were operating at 69% capacity factor in 1970, which further dropped to 53% by early 80's. Electricity demand was expected to rise in the 90's, due to bludgeoning variety and quantity of electric appliances. Greater efficiency at end-user level was likely to slow the demand growth moderately. In addition to an increase in overall demand, it was speculated that capacity utilization of existing facilities would increase by 2000 due to restricted development of new electric utilities. On the contrary, the 90's witnessed a repressed growth in electricity demand. In 1995, electricity demand growth was even lesser than forecasted in EIA's *Low Case* scenario forecasts drawn in latter 80's. By the mid 90's, there was a saturation of new electric appliances and in spite of a boom in computer industry, correlation between electricity and GDP growth was decreasing and the least observed in last 4 decades (Table 3.1). This fact highlights the difficulty forecasters faced in gauging the correlation between GDP and electricity demand growth from 70's to 90's and resulting inaccuracy of forecasts.

3.6 EIA Forecasting Methodology

EIA divides energy forecasts into components (by source of energy, end-use, geographical regions etc.) that are each projected independently. The total energy consumption may be broken down according to the sources as following:

Non-electric utility fuels – Petroleum, natural gas, coal

Electric utility fuels – Petroleum, natural gas, coal, nuclear, hydropower

A two-pronged approach leads to the final energy demand projections and determination of percentage contribution from various fuel sources.

Top-down Approach

Overall energy requirement is estimated and distributed amongst the various energy sources as per availability and feasibility. The contribution of each source is selected on a cost efficiency basis. For example, the most economic plants like coal-fired steam and nuclear satisfy base load. They operate almost continuously with the exception of scheduled maintenance and predicted forced outage interruptions. Turbines are used to satisfy intermittent peak loads only due to highest operation costs.[8]

Bottom-up Approach

Supply projections from each energy source are based on existing capacity, plans for further expansions for these sources,[9] regulatory and political issues causing a shift in use

[8] They are also used to compensate for unforeseen excess demand at short notice

[9] IFFS accounts for capacity expansion projects in planning or construction stages referred to as "pipeline builds" as well as "new" builds which are part of the IFFS decision process. These builds are determined by IFFS as necessary capacity additions to existing and pipeline plans in order to meet anticipated future demand or for replacing current stock. The "new" builds might never be implemented; therefore they lend a degree of uncertainty to the energy projections.

of different energy sources etc. These estimates are aggregated to arrive at the overall energy figures.

Results from both the approaches are reconciled to give final estimates. Such a methodology allows imposing constraints at the overall as well as component supply level. Uncertainties specific to different sources of energy notwithstanding, source-wise energy forecasts tends to be more inaccurate than overall energy estimates. The demand for all forms of energy from various sources is interrelated due to the substitutability among different fuels and energy forms.[10]

3.7 Forecasts over Different Time Horizons

Generally forecasts extend over different horizons to serve different purposes: short, medium and long term. Short-term forecasts may extend from a quarter to two years, medium term from two to five years and long term from five to ten years [Makridakis 1990].

Short-term forecasts**:** These are critical for planning and operating existing facilities. They track daily, weekly and seasonal climatological and weather variations. They are supposedly the most accurate due to shortest lead times and repetitive nature of seasonal patterns (disrupted by rare events like catastrophe, war etc.). They are used in conjunction with weather forecasts to refine load estimates.

Medium term forecasts**:** These are helpful for capital budgeting purposes. These forecasts point to the timing of recessions and economic cycles. Their uncertainty and inaccuracy increases as forecast horizon increases.

[10] E.g. natural gas can replace electricity or coal-fuel electricity can replace petroleum; Fuels may also be converted into energy via electricity or by direct combustion.

Long-term forecasts: These are essential for capital expansion plans and preparing long-term goals. They account for anticipated new technologies, products, consumer needs, societal attitudes and political regulations. Due to longer forecast horizon, these forecasts are subject to maximum uncertainty.

3.7.1 Medium to Long-Term Forecasts for Total U.S Energy Consumption

Similar to energy forecasts based on GDP growth rate, EIA prepares a range of forecasts assuming three oil price scenarios – low, middle (base case) and high. Planners can adopt any set of forecasts based on their expectations of future trends. Major swings in oil prices make it challenging to rely on historical patterns.

Oil prices fluctuate with economic and population growth, along with the more unpredictable technological development.[11] Energy requirements are directly impacted by changing trends in oil prices. The base case oil price projections for 1990 made in year 1981 were reduced by 35% in year 1982. Figure 3.2 indicates how much the high and low case oil price forecasts deviate from the base case. The expected mean of oil prices in high and low price scenario can deviate from that in the base case by as much as 40%, pointing to the high degree of uncertainty.

EIA prepares three sets of energy forecasts based on the above oil price scenarios (*Low*, *Base* and *High Case*). Figure 3.3 depicts 1981 U.S. energy consumption forecasts based on oil price scenarios shown in Figure 3.2. The deviation of expected mean in high and low case from that in base case is compressed to 5%. Figure 3.4 plots all the three sets of 1981 energy forecasts (Figure 3.3) against actual values for the same period: all of them were inaccurate.

[11] If technological innovation increases efficiency, oil requirements are expected to reduce. Although innovation in the field of motor industry during the 50's led to unforeseen levels of oil demand.

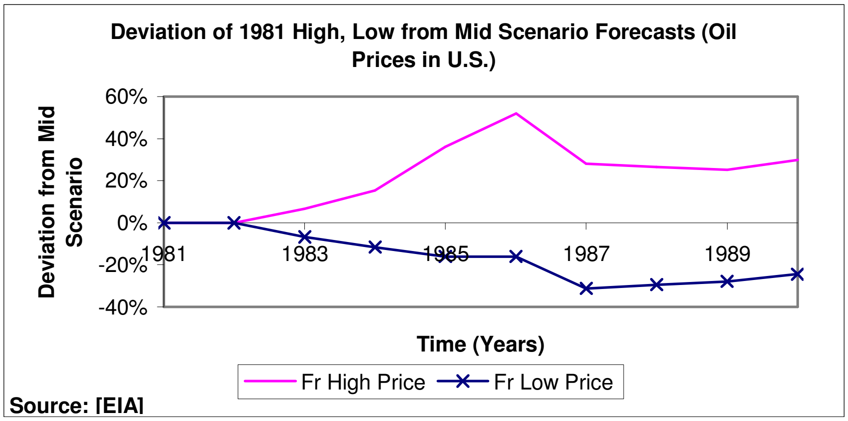


Figure 3.2: Deviation of 1981 High, Low from Mid Scenario Forecasts (Oil Prices in U.S.)

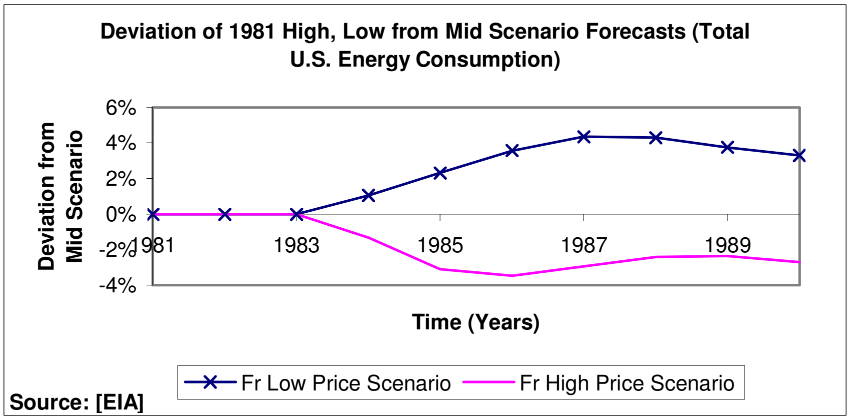


Figure 3.3: Deviation of 1981 High, Low from Mid Scenario Forecasts (Total U.S. Energy Consumption)

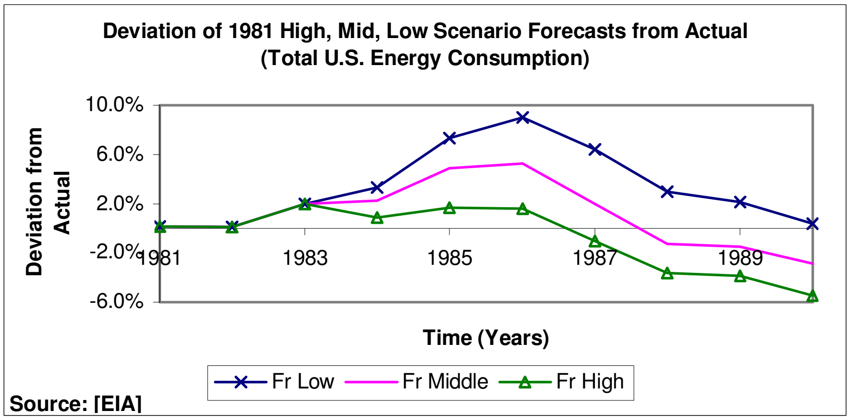


Figure 3.4: Deviation of 1981 High, Middle, Low Scenario Forecasts from Actual (Total U.S. Energy Consumption)

If decisions were based on expected values in any one of the three scenarios, they could be incorrect. Incidentally, these forecasts can be viewed to represent demand distribution. Instead of choosing any particular forecast with the maximum probability of occurrence, planners could attach probability distribution to various demand values between the *low* and *high case* forecasts. (In Figure 3.4, actual demand lies somewhat within the 1981 *high* and *low case* forecasts).

These results and conclusions are not exclusively for the year 1981; Figure 3.5 substantiates the same in other years. It compares actual values for total U.S. energy consumption with base forecasts drawn in 1982, 1985 and 1987. The energy consumption was decreasing in 80's as appliances were becoming more efficient (See Section 3.5). It is challenging to foresee such changing trends accurately, so note the drastic change in forecasts from being optimistic to pessimistic from1982 to1987.

3.7.2 Short-Term Forecasts for Total U.S. Energy Consumption

Arguably short-term forecasts should be more accurate than long-term forecasts because the prediction horizon is short [Makridakis 1990]. Yet short-term forecasts were found to be equally inaccurate. Figure 3.6 shows the deviation between actual values for U.S. energy consumption and quarterly forecasts prepared in January 1986, July 1986, January 1987 and October 1987. The data shows that EIA's long and short-term total energy consumption forecasts have approximately ±10% errors.

3.7.3 Revisions in Long and Short-Term Forecasts

Forecasters "*learn*" from prevailing trends and adjust their outlook constantly. The year to year demand growth in 1986 was lower than that predicted in 1985 and higher in 1987 (Figure 3.7). Accordingly, the forecasts in year 1986 and 1987 were revised.

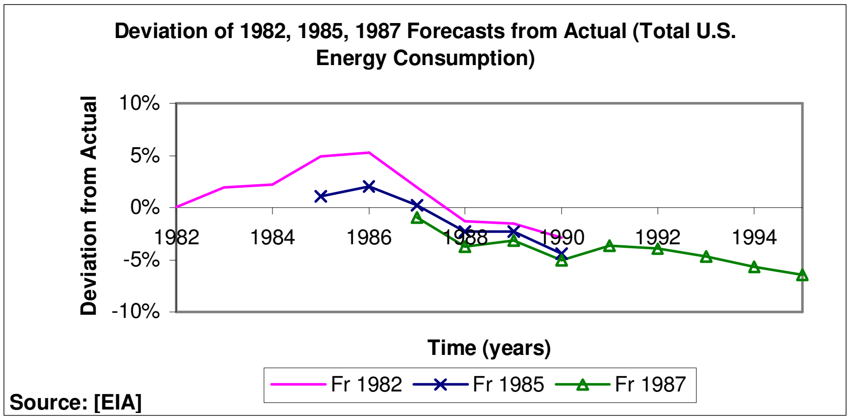


Figure 3.5: Deviation of Long Term Forecasts from Actual (Total U.S. Energy Consumption)

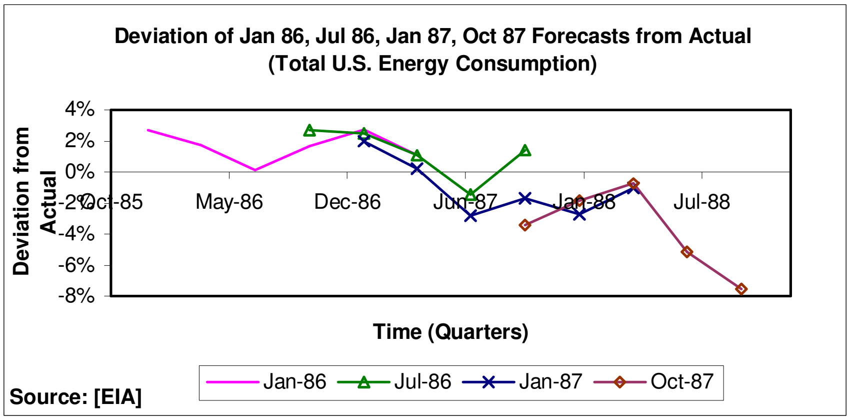


Figure 3.6: Deviation of Short Term Forecasts from Actual (Total U.S. Energy Consumptions)

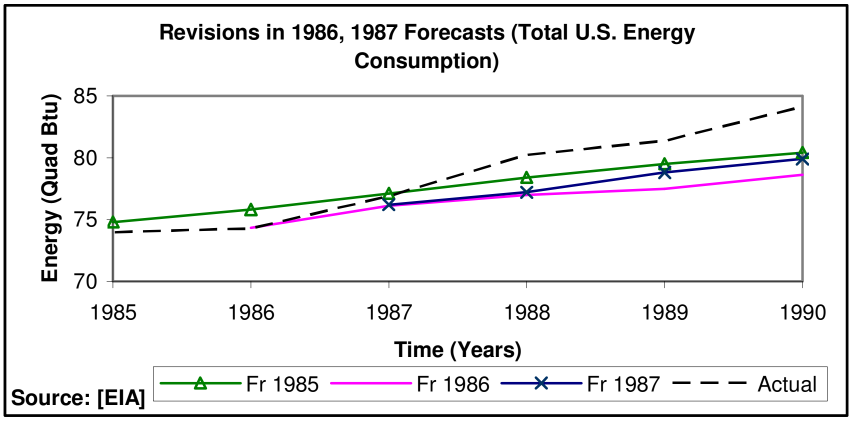


Figure 3.7: Revisions in 1986 and 1987 Forecaszts (Total U.S. Energy Consumption)

Such revisions based on availability of new information leads to multiple values of expected demand for any particular year in future. This suggests that decisions should be based on an expected distribution of expected demand rather than the expected mean values.

The probabilistic hydropower capacity planning model presented later in this thesis also incorporates a feedback from prevailing trends to adjust future forecasts to minimize discrepancy between forecasted and simulated demand (See Section 6.3).

3.8 Forecasts for Hydropower Energy Consumption in U.S.

Hydropower energy forecasts are also found to be even more imprecise than overall energy forecasts (Refer to Section 3.6). Total energy forecasts were within ±10% of the actual values; hydropower forecasts over the same time period could be erroneous by as much as 40%. Contrast the results for total and hydropower U.S. energy consumption demand in Figures 3.5 to 3.7 and Figures 3.8 to 3.10. Hydropower generation and demand shows greater variability due to shifting precipitations levels and substitutability of demand between other sources of energy. Hydropower is not the primary source of energy in the US economy. It acts as a buffer source to augment or absorb deficit or excess overall energy generated. Therefore it is subject to greater uncertainty than overall energy.

The findings in Table 3.2 are unique because this table is adapted from an EIA publication, where it is acknowledged that such errors manifest in spite of sophisticated models due to extremely high unpredictability of precipitation. This table lists errors observed between actual and forecasted values of U.S. hydroelectricity generation

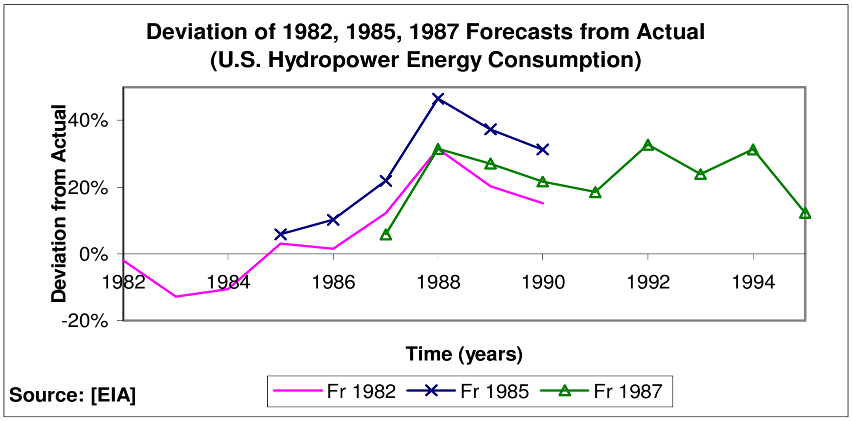


Figure 3.8: Deviation of Long Term Forecasts from Actual (U.S. Hydropower Energy Consumption)

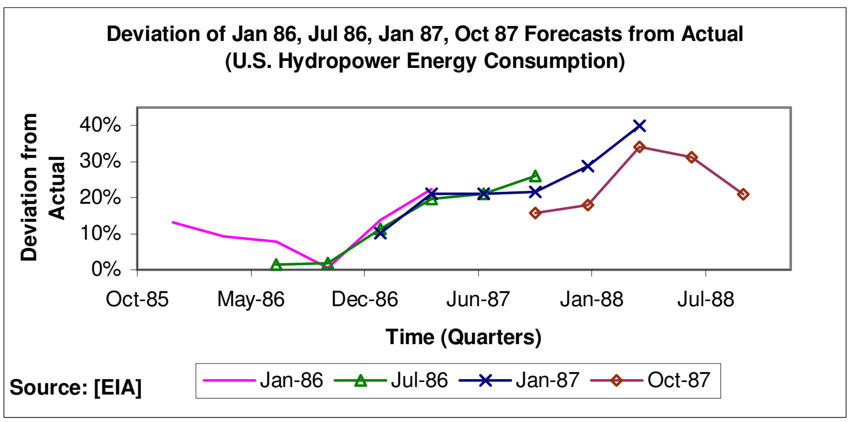


Figure 3.9: Deviation of Short Term Forecasts from Actual (U.S. Hydropower Energy Consumption)

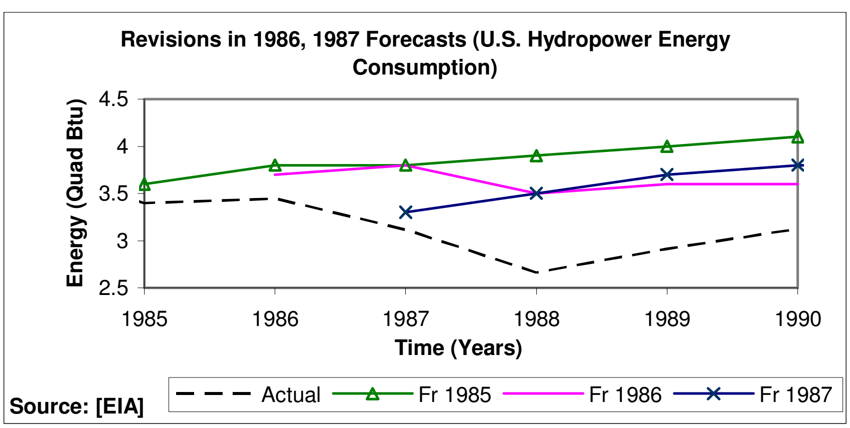


Figure 3.10: Revisions in 1986 and 1987 Forecasts (U.S. Hydropower Energy Consumption)

The actual value for each quarter is given in column 2. Row 1 indicates forecasts made for 2Q 87 from 2Q 86 to 1Q87 at the beginning of each quarter. Some quarters show forecasts for the current quarter. This is because the forecasts are drawn at the beginning of each quarter, whereas the actual statistics are gathered at the end of each quarter. It is evident that errors decrease as forecast horizon decreases from 5 quarters to just a quarter away. But note the high degree of uncertainty in forecasts spaced just a quarter apart.

Table 3.2: Actual Vs Forecasts of Hydroelectricity Generation in US (Billion KWh)

	Actual	2Q 86	3Q86	4Q 86	1Q 87	2Q 87	3Q 87	4Q 87	1Q 88	2Q 88
2Q 87	67.1	-24.4	-24.4	-26.1	-10.6					
3Q 87	56.8		-26.5	-25.5	-25.5	-22.9	-14.8			
4Q 87	55.9			-25.6	-25.4	-25.4	-21.1	-17.9		
1Q 88	60.9				-34.8	-34.6	-27.9	-20.5	-15.9	
2Q 88	59.2					-42.6	-35.3	-35.3	-24.2	-11.7

Source: [EIA *Short Term Energy Outlook* 1992]

4 Traditional Hydropower Capacity Planning

4.1 Literature Review

This chapter reviews current practices in hydropower capacity planning. The traditional capacity planning approach has been "*deterministic*". This implies a stationary view on expected demand and design of excess capacity in advance to meet future demand. The excess capacity in anticipation of future demand is called "*overcapacity*". Determination of *optimal overcapacity* or plant-size selection for engineering and manufacturing facilities has been a key challenge for engineers and planners. This study is based on the works of eminent economists and engineers in the field of capacity planning such as Hreinsson, Chenery and Manne.

Hreinsson's [1990] practical view of hydropower capacity planning problem has been used as a representative view of current planning practices. He has conducted empirical and theoretical analysis in the context of Icelandic power system. The Icelandic power system is an ideal case study since it is based almost entirely on hydroelectricity. Focusing on hydropower systems exclusively eliminates modeling complications arising from the capacity distribution between various sources of power. The generic results of this study may be translated to other hydropower-based systems too.

Economies of scale is of crucial in hydroelectric capacity planning. Chenery [1952] made significant contribution to the power demand-supply modeling and capacity planning by demonstrating the effect of economies of scale on investment behavior. His models established that given the cost function for power generation and demand estimates, one can find the optimum solution for planned capacity vis-à-vis output. This solution is a function of economy of scale, discount rate, planning period and demand forecasts. He also introduced the concept of "*overcapacity*" as discussed above. He presented graphical solutions to show the effect of these variables on optimum overcapacity.

Manne's [1961] work on capacity expansion planning and investment decisions stems from Chenery's work. He examined the problem of determining optimal degree of excess capacity for new production facility. He also investigated the effect of economies of scale and demand growth on capacity planning. Unlike Chenery, Manne used probabilities in place of constant rate of growth of demand in his theoretical work. Manne also conducted empirical case studies on planning investments in a series of future manufacturing units. For simplification, Manne used a deterministic approach in these studies. He conducted extensive numerical experiments to obtain feasible solutions, which were then compared with the actual solutions being used in the industry. The following section presents the framework of deterministic analysis.

4.2 Deterministic Capacity Planning

Deterministic capacity planning approach does not account for risk of future uncertainty. The analysis rests on expected mean of each parameter instead of the possible distribution. In addition, such an approach ignores the sequential nature of investment and decision- making. The only way such design approach addresses uncertainty is by the way of sensitivity and scenario analysis. The study in Chapter 3 demonstrated the inaccuracy of demand forecasts. In his theoretical work Manne opposes the replication of probability distribution with a single value for any parameter. Yet for ease of calculation he resorts to the deterministic models for his empirical studies [Manne 1967].

The fundamental goal in development of any production facility is to satisfy specific demand at minimum cost. Chenery and Manne propose various models for estimating costs as a function of capacity expansion. Hreinsson used Manne's work as a foundation to determining optimal parameters for single and sequence of hydro power plants. This thesis uses the same terminology and notation as in Hreinsson's work.

4.3 Unique Aspects of Hydropower Planning

These are unique aspects of hydropower planning, unlike other facilities with similar cost-profile.

No Backlogs: Residential or industrial consumers can not be subjected to light-outs due to power shortage. There have been cases of light-outs due to unforeseen demand but at the planning stages, all attempts are made to provide excess capacity to avoid such a situation.

Substitutability of Energy Sources: Hydropower is not the primary source of energy in U.S. Even if the forecasts for total energy requirement are reliable, the distribution of energy among sources such as petroleum, coal or hydro-based plants remains flexible, which makes it impossible to predict the source-wise contribution precisely.

No Salvage Value: Hydropower plants do not have any salvage value. These are typically controlled by government agencies and have life periods of 50 years or more. Therefore the NVP analysis treats cash flows from dams as being equivalent to perpetuity. Once the resources have been committed to the construction of such a plant, not only the decision is irreversible, the dam can never be demolished to recover invested capital.

Inelastic Economics: Overall electricity prices are elastic in regulated markets but it does not translate to hydroelectricity prices. Source-wise electricity prices are not determined by end-user market economics; utilities draw long-term or short-term contracts for hydroelectricity prices, making it easier to model them.

4.4 Deterministic Capacity Planning Model

Electricity demand is segregated into two components – *basic* demand (BD) and *extra* demand (ED). BD is the base case demand posed by residential and light industrial units, which is expected to grow linearly at a predetermined rate. ED is the demand posed by energy intensive industries and it is superimposed on BD in a step-wise manner. In most cases it is assumed that the hydropower plants are bound to satisfy the BD at all times and customers pay for the privilege of continuous power supply. The management is not obliged to satisfy ED, requiring negotiation of long-term contracts with predetermined prices typical of bulk quantities of energy.

4.4.1 Model Parameters

This section examines Chenery's [1952] and Manne's [1961] basic capacity expansion model for BD only. The layered complexity of meeting ED is discussed in Section 6.2.2. This model provides a foundation for all power demand-supply models presented in the thesis and stresses the impact of economies of scale on selection of *optimal* capacity and investment decisions.

This model was developed as a result of Chenery's work in the natural gas industry. This industry is characterized by high front-end capital investments and low operational costs. Likewise cost profile in the hydropower industry justifies applying this model to hydropower capacity planning.

4.4.2 Economies of Scale

The premise of this model is that overcapacity is desirable in spite of perfect demand forecasts, if economies of scale are sufficiently high. Given variables such as production function, discount rate, planning period; Chenery outlines a method to estimate *optimum* overcapacity.

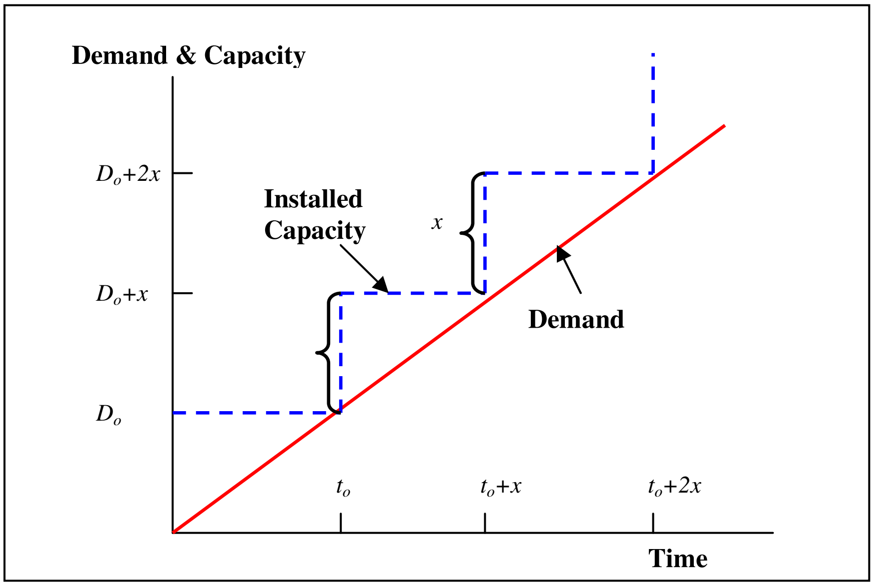


Figure 4.1: Demand and Capacity Growth

Figure 4.1 shows the growth of basic demand and capacity over time. Some simplifying assumptions:

1. Linear growth of demand over time
2. Infinite equipment life
3. When demand equals existing capacity, x units of new capacity are installed

Unlike Chenery, Manne opted for an infinite planning horizon due to sufficiently high design life of facilities under review. Figure 4.2 charts a saw tooth pattern of overcapacity over time; similar to Wilson-type inventory model [Arrow 1951].

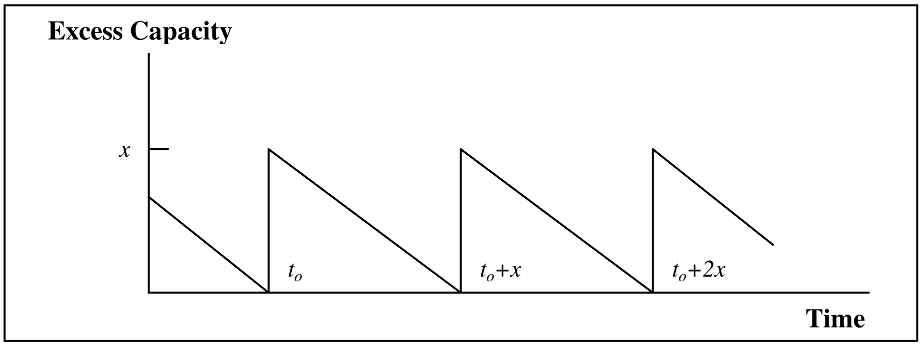


Figure 4.2: Growth of Demand and Capacity over time

For convenience, assume unit capacity (or demand) equals one year's growth in demand; then this saw tooth cycle repeats itself every x years.

The installation costs for single capacity increment of size x may be represented by a cost relationship in the form of a power function:

$$Cost = kx^{a} \qquad (k > 0;\ 0 < a < 1). \qquad \textbf{\textit{Equation 4.1}}$$

Such a cost relationship verifies economies of scale in construction because the change in costs for increasing base capacity decreases as the base capacity increases. Equation 4.2 mathematically proves that partial differential of *Cost* with respect to x decreases as x increases (only if $0 < a < 1$).

$$\frac{\partial Cost}{\partial x} = kax^{a-1} \qquad \textbf{\textit{Equation 4.2}}$$

For $a = 0.5$, this cost function implies that it is only twice as expensive to build capacity worth four times larger. As mentioned previously, pronounced economies of scale in construction and operation of hydropower plants encourage engineers to build over capacity well in advance of anticipated demand. The key challenges are:

- What should be the optimum capacity?
- How many years worth of future demand to build for today?

The prevailing interest rate plays an important role in these decisions.

4.4.3 Determination of Optimum Capacity

Without discounting, the value of a unit of currency's worth would not change over time. It would be equivalent to spend a dollar amount now as in the future. If there were no discounting, there would be no limit on the amount of expenditure made today in order to save costs in the future. In the past, engineers have been known to side step the concept of discounting, as observed in the case of Aswan High Dam [Shibl 1971]. However discounting plays an important role in modern investment decision-making. The parameter r is the "discount rate". Throughout, present value of a dollar due t years in the future will be expressed as e^{-rt}.

Points corresponding to t_o, t_{o+x} or t_{o+2x} in Figure 4.1 mark the times at which previous capacity equals current demand and additional capacity has to be installed in the system. Such a point is known as the "*point of regeneration*". By choosing an infinite planning horizon, the future appears identical to the scenario x units of time back at any point of regeneration. If $C(x)$ is a function of x that is used to represent the sum of all discounted future costs looking forward from a point of regeneration[12]:

$$C(x) = kx^a + e^{-rt}C(x) \qquad \textbf{\textit{Equation 4.3}}$$

The first term in this recursive equation indicates the installation costs of a new facility. (See Equation 4.1). The second grosses the sum of installation costs incurred at each point of regeneration in the future, discounted from every point of regeneration to the current point. There is a difference of x years between any two consecutive points of regeneration, same as the measure of excess capacity installed at every point.

[12]It is assumed that decrease in future costs due to increased efficiency in construction process would be cancelled out by the increase in costs due to inflation.

Minimizing *C(x)* gives the value of the economies of scale parameter *a*. Equation 4.3 is rewritten to simply minimization:

$$\frac{C(x)}{k} = \frac{x^a}{1 - e^{-rx}} \qquad \textbf{Equation 4.4}$$

Taking log of both sides:

$$\log C(x) - \log k = a \log x - \log(1 - e^{-rx}) \qquad \textbf{Equation 4.5}$$

To minimize *C(x)*, differentiate log *C(x)* with respect to *x* and set the result equal to zero:

$$\frac{d \log C(x)}{dx} = \frac{a}{x} - \frac{re^{-rx}}{1 - e^{-rx}} = 0 \qquad \textbf{Equation 4.6}$$

Solution of Equation 4.6 (*x'*) is the optimum capacity size. The system capacity is incremented by *x'* units in every *x'* years. Juggling Equation 4.6:

$$a = \frac{rx'}{e^{rx'} - 1} \qquad \textbf{Equation 4.7}$$

With Equation 4.7, the optimal increment *x'* may be determined for any choice of parameters *a* and *r*.

4.4.4 Example

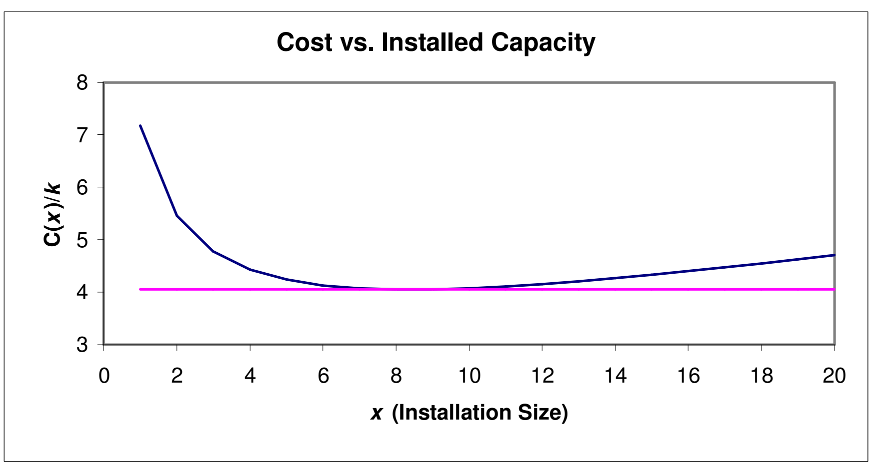


Figure 4.3: Graphical Solution to Optimal Capacity Size

For $a = 0.5$; $r = 0.15$; $D = 0.05$ units

Minimum cost expressed as $C(x)/k = 0.905$ units

This is achieved for $x = 8.4$ year's worth of demand growth.

The optimal solution for this example is can also be deciphered from Figure 4.3.

4.4.5 Sensitivity Analysis

To investigate the effect of r on optimal capacity level x', sensitivity testing may be conducted. For constant values of a, partial differentiation of Equation 4.7 gives:[13]

$$rdx' + x'dr = 0 \qquad \textbf{\textit{Equation 4.8}}$$

Since x' and r are positive, Equation 4.8 suggests:

$$\frac{dx'}{dr} = -\frac{x'}{r} < 0 \qquad \textbf{\textit{Equation 4.9}}$$

Differential of optimal size over interest rate being negative implies that the optimal size will be smaller for higher discount rates.

Figure 4.4 shows $C(x)/k$ as a function of x for various combinations of parameters a and r.

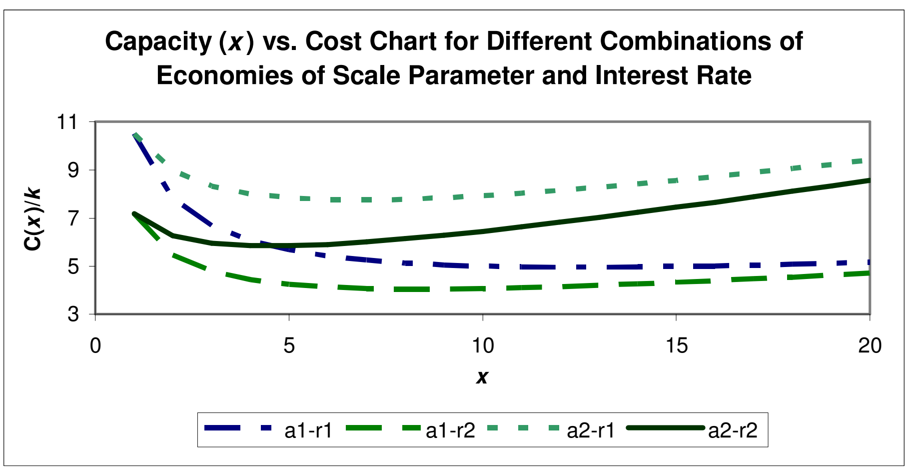


Figure 4.4: Capacity vs. Cost Chart

[13] Since Equation 4.6 is written as a function of rx', the partial differential of rx' has to be equal to 0

Empirically observed values are chosen for both *a* and *r*: $a_1 = 0.50$; $a_2 = 0.70$; $r_1 = 0.10$; $r_2 = 0.15$ [Manne 1967]. Visual inspection of Figure 4.4 confirms that there exists an optimal capacity size which minimizes costs. Figure 4.4 also corroborates analytical conclusions drawn from Equation 4.9: *x'* decreases as *a* increases for fixed *r* or interest rate *r* increases for fixed *a.* Figure 4.5 traces the relationship between *a* and *x* for different values of *r*.

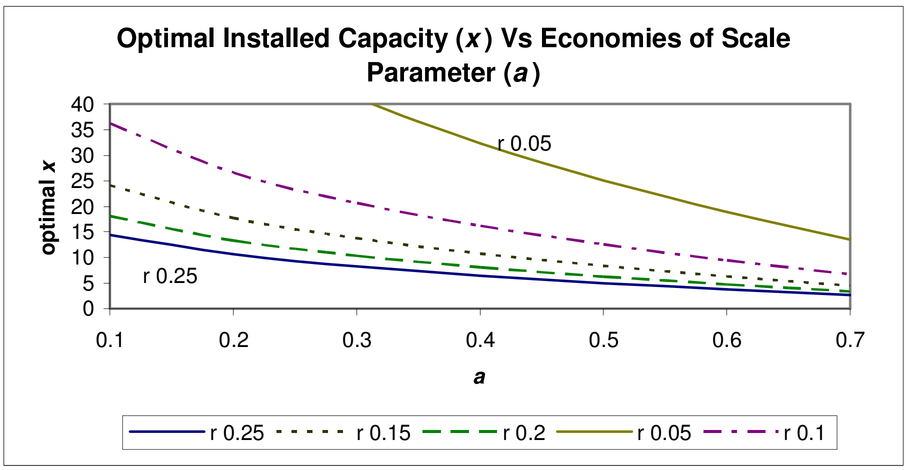


Figure 4.5: Optimal Installed Capacity Vs Economies of Scale Parameter

An interesting observation is that the cost does not vary significantly within a wide range of capacity values (*x*) beyond the optimal point (*x'*). In the a_1-r_1 case (Figure 4.4), costs increase by 3.4% only as capacity increases 100% from 10 to 20. Similar cost increment is much steeper for variation of capacity size on the lower end of the spectrum. Therefore this model is more sensitive to undercapacity than overcapacity. Such a relationship induces a tendency to build big in advance. This leads to financial efficiency due to excess energy production or under-utilization of committed resources if demand forecasts are too optimistic.

5 Real Options

This chapter introduces the fundamentals of Real Options analysis (ROA). It begins with a qualitative and quantitative explanation of ROA. A few simple examples communicate the practical application of ROA and its advantages over other decision-making criterion. A realistic example of capacity planning in tunnel construction serves as an introduction to application of ROA in hydropower capacity planning. The chapter showcases how ROA is used to determine optimal resource utilization and capacity planning policy.

5.1 Options Pricing Theory

Options Pricing Theory as it is known today is rooted in the seminal work of Fischer Black and Myron Scholes for which they won a Nobel Prize in 1997 [Black and Scholes 1973]. An *Option* is the right, but not the obligation to buy (if *call*) or sell (if *put*) a specific asset at a pre-paid price (called *exercise* or *strike* price) on or before a specified date (called *maturity* date). An *American Option* can be exercised before the maturity date and *European Option* can be exercised only at the maturity date. Options are used to manage the uncertainty due to movements of *underlier* value. Underlier can be financial or real assets such as common stock, stock indices, commodities or capital projects. If the option is not exercised, holder loses the premium paid to obtain the option. Protection from downside risk with the possibility of a large upside potential creates an asymmetric situation, which drives option prices.

There are two main types of options: financial and real options. de Neufville [2003b] further classifies Real Options as options *on* projects and options *in* projects (See Figure 5.1). There is an analogy between Real Options and financial options. Examples of financial options are *Calls* and *Puts* on financial assets such as a stock. You may buy

(European *Call* on stock) or sell the stock (European *Put* on stock) if the strike price is below (*Call*) or above (*Put*) the current stock price but you are not obliged to do so. A Real Option is like a *Call* or *Put* on financial assets. A choice but not the obligation to expand a project if the outcomes are favorable (installing another manufacturing plant if demand is growing at a healthy rate) or contracting a project (shutting down the manufacturing factory partially if demand does not pick up) is akin to financial *Calls* and *Puts*. Being options on real assets, they are called Real Options.

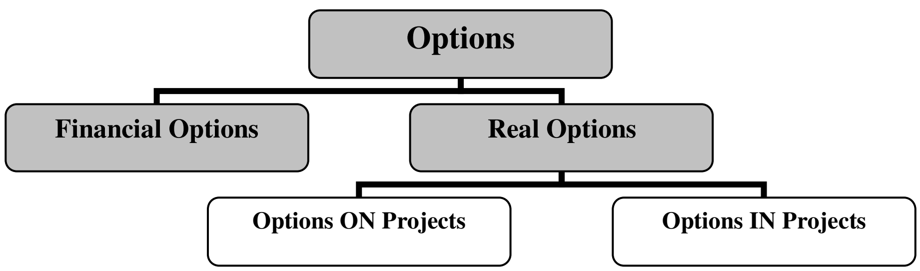


Figure 5.1: Different Types of Options

5.1.1 What are Real Options?

Stewart Myers [1977] introduced the term "*Real Options*" in reference to the extension of "Options Pricing Theory" to the financial valuation of "real assets" subject to uncertainty with scope for managerial flexibility. According to de Neufville and Neely [2001], Real Options evaluation methodology recognizes that an active management can manage risk by avoiding bad outcomes and taking advantage of good outcomes. The intuition is simple yet profound – management's rational decisions skew the distribution of possible outcomes towards the upside and minimize downside potential. ROA accounts for uncertainty by considering various possible outcomes and strategic decision-making flexibility, which gives a higher valuation for the same project (than traditional valuations). ROA is particularly useful while evaluating investment strategies with high risks, uncertainty in conjunction with managerial flexibility. As seen in Chapter 4, traditional valuation methodologies often fail on these accounts by assuming fixed outcomes and static decision pathways. ROA distills the best features of Net Present Value and Decision Tree Analysis without their failings.

ROA attracted academic attention in the 80's and early 90's but Real Options gained traction as a valuable valuation and strategic decision-making tool only in mid 90's. There has been much research on application of ROA for project valuation, mostly in the last decade [Dixit and Pindyck 1994; McDonald and Siegel 1986, Ingersoll and Ross 1992; Trigerogis 1996; Luehrman 1998; Copeland 1998a; Amram and Kulatilaka 1999; Benaroch and Kauffman 1999; de Neufville 2001; Schwartz 2001]. The major proportion of research and publications on Real Options has been devoted to options *on* projects, while options *in* projects are yet to find wide-spread recognition in academia and industry.

5.1.1.1 Options on Projects

These are options in capital budgeting decisions such as the option to expand, contract or defer projects. In evaluating these options, the projects are treated like a blackbox without considering specifics of system design. A majority of literature on Real Options addresses these types of options. They are particularly interesting to economists and finance professionals.

5.1.1.2 Options in Projects

These are options which involve a change in system design or underlying technology as uncertainty is resolved. Embedding such options requires a detailed understanding of the system and operations. They are particularly interesting to system engineers. Limited literature is available on this topic and it has yet to gain sufficient academic and industrial attention. Some published examples of options *in* projects:

- Alternate investments options in technology R&D by based on 4 scenarios of competition in market: The likely impact of investments currently under consideration and judging current value of future impacts [Rouse et al, 2000].
- The option to vary size and timing of manufacturing capacity increments [Trigeorgis 1996].
- R&D investment and commercialization options for new or unique products with no antecedents and comparables like color printers at Kodak [Faulkner 1996].
- The option to bring new products to the market by controlling research activity from inside the company or in partnership with others [Neely 1998].

Table 5.1 shows how ROA scores over conventional methodologies as a decision making criterion based on multiple metrics.

Table 5.1: Key Criteria for Decision Making Tools

	Cash Flow based	Risk Adjusted	Multi-Period	Captures Flexibility
Real Options Analysis	Yes	Yes	Yes	Yes
NPV/ DCF	Yes	Yes	Yes	No
Decision Trees	Yes	No	Yes	Yes
Economic Profit	Yes	Yes	No	No
Earnings Growth	No	No	No	No

Adapted from [Copeland 1998]

5.2 How to Analyze Real Options?

The cornerstones and approach to analyze RO *in* and *on* projects are considerably different. Some important concepts and approaches for valuing both the types of RO are listed below.

5.2.1 Real Options on Projects

Though these are the most commonly encountered RO in literature and actual practice, in spite of numerous books, articles and academic discussions, there is no consensus on the analytical approach and underlying assumptions for application of ROA in the context of different industries and types of options. Borison [2003] summarizes the suitability, pros and cons and mechanics of various approaches developed by academicians and practitioners. Some common approaches are:

5.2.1.1 No Arbitrage Approach

The classic Options Pricing Theory (OPT) applied for pricing financial options stands on the concept of *Risk-Free Arbitrage*. Intuitively arbitrage is associated with buying low and selling high in the market *simultaneously*. The timing is important because the arbitrageur requires no personal investment but only needs to set up contracts such that the revenue of selling contracts pays off the cost of buying contract. The arbitrageur bears no risk in such a transaction, thus it is termed as risk-free arbitrage. It is the quintessential "free-lunch" but in real world, there are seldom any "free-lunches". Arbitrageurs immediately bid away any potential arbitrage opportunities by setting up contracts to realize gains from this opportunity and thereby moving the markets in direction opposite to the arbitrage opportunity. In this situation, the price of a financial security does not depend on the underlying distribution or expected value, rather it is arbitrage enforced. Arbitrage enforced Real Options can be valued by the following methods [Mun 2002]:

- ***Closed Form Solutions***: Like the Black Scholes formulation and its modifications. It is applicable where equations can be solved analytically given a set of input assumptions. They give exact solutions and are easy to implement but are difficult to explain methodologically because they rely on highly technical stochastic mathematics. They are also restricted by their specificity and limited modeling flexibility.

- ***Partial Differential Equation (PDE)***: Also called the finite difference method – Real options pricing problems are often more "exotic" than financial options (several underlying variables and multi-factor models). Indeed only a small fraction of PDE's have analytical solutions and finding that solution is an arduous task. However, several techniques for finding numerical solutions to PDE's have been outlined.
- ***Lattice Methods***: Like Binomial, Trinomial, Multinomial methods – they are the most widely accepted method of ROA. They are easy to implement, provide an intuitive understanding of movement of the value of underlier and contingent options. But they are computationally challenging. If Binomial lattices are used, they can be solved by computing a risk-neutral probability measure.

  Risk Neutral Probabilities (RNP): In a risk-neutral world, RNP is the pretend probability of outcomes the up and down node of lattice such that expected return equals the risk-free rate [Brealey 1991]. The RNP weighted cash flows in up and down case can now be discounted at the risk-free rate to compute the expected outcome. The RNP has no tangible meaning and it is not at all related to the probabilities of occurrence of any specific event.

$$RNP = \frac{R_f - d}{u - d}$$ ***Equation 5.1***

R_f = Risk-free rate

d = returns in down case and u = returns in the up case

The option value is the difference between expected outcome in the no-option case and that in the case with option. (See Section 5.6.1 for practical application).

- ***Simulation Processes***: Monte Carlo Simulation with Optimization method – they can be used to value options when the above techniques are analytically or computationally difficult to apply. Instead of generating a lattice to determine the movement of the underlier and the option value, the simulation model can generate a distribution of the underlier and the probabilities of manifestation of a particular value for the underlier. The value of the option can be easily calculated based on these analytics. (Explained in greater detail in Section 5.3).

5.2.1.2 Decision Tree-Based Analysis

Decision Tree Analysis (See also Section 2.4.6.) does not yield the accurate option value because it is based on expected value of underlying variables [de Neufville 2003b]. The right value can be obtained by computing the risk-adjusted discount rates for each branch of the tree and actual probabilities of occurrence of particular events, which is a difficult task. DTA serves as a good measure to introduce the idea of optionality or flexibility in projects and find its approximate value.

5.2.1.3 Hybrid Model

The hybrid model of valuing real options combines the best of DTA and conventional ROA methodologies. de Neufville and Neely [2001] demonstrate the application of hybrid model in evaluating risky products development projects. They use the no arbitrage pricing approach to evaluate the market risk and a decision-tree based approach to assess the project related risk. This approach allows manager to manage risk by focusing on dynamic strategies of development, rather than on specific products or projects. They conclude that managers can obtain a higher value for any project by avoiding unfavorable outcomes and taking advantage of favorable outcomes by embedding options in the project which can be exercised or abandoned as uncertainty resolves in future.

5.2.2 Real options in Projects

Such options are valued differently than the options on projects. While dealing with the value of flexibility in projects, it is not easy to justify that the cash flows can be replicated by a portfolio of financial assets, so no-arbitrage enforced valuation is not applicable. Instead this valuation is based on the actual probability of occurrence of the outcomes. The expected mean of the cash flows without any flexibility is compared with the expected mean of outcomes for the flexible case. A distribution of outcomes contingent on distribution of input parameters and probability of actual occurrence can be constructed analytically (See Section 5.6.2) or via Monte Carlo Simulation (See Section 6.3). The difference in outcomes is taken as the value of incorporating flexibility in the system. The lattice of input parameters is different from that constructed in the option *on* projects: it is a *path dependent* lattice in which subsequent values are a function of preceding values.

5.3 Monte Carlo Simulation

Monte Carlo simulation (MCS)[14] is a *stochastic* tool, which repeatedly generates random values for uncertain variables to simulate real-life situations. *Simulation* is an analytical method that attempts to predict and imitate behavior of real-life system by creating an

[14] MC simulation was named after Monte Carlo, Monaco, where the primary attractions are casinos with games of chance like Roulette Wheel, dice and slot machines, card games etc. The common feature of all these games is that the sample space of all possible outcomes is well defined but result of an individual trial is known only probabilistically. For instance, you could draw any number from 1 to 6 in roll of a fair die but the result of any trial is not known with certainty.

approximate (mathematical) model. *Stochastic* processes relate to uncertain random variables and corresponding probability distributions. This technique can be applied to any random variable with a known or estimated range of values but an uncertain value for any particular time or event.

One of the drawbacks of traditional valuation methodologies like NPV or CBA is the assumption of single stream of cash flows. Due to uncertainty, one can not be confident about the accuracy of these results. *Sensitivity analysis* demonstrates the effect of varying a single variable; *Scenario analysis* shows the effect of a limited number of combinations of variables; MCS constructs *all* the possible scenarios.

Steps for generating MCS (See also Appendix A):

- Model interdependencies between various governing parameters in the model via a set of mathematical equations.
- Input probabilistic distribution of crucial variables subject to uncertainty. Distributions can be derived from empirical data, experience or logic.
- Draw a random sample (using a random number generator function) from the distribution domain of primary variables and calculate the desired end-result value using the model.
- Repeat the process multiple times, each time computing the new end-result and storing the value. This allows generation of probabilistic distribution of end-result, which can be used to calculate characteristic statistics.

While MCS is an excellent tool for handling complex and large-sized problems dealing with uncertainty, it suffers from a few limitations:

- Even the most sophisticated models with unbiased probabilistic inputs can not replicate real-life situations. Management will understand and commit to MCS results contingent upon their faith in accuracy of the underlying model.
- MCS does not suggest a well-defined decision strategy. Suppose the management chooses to base a decision on the probability distribution of the expected NPV, there are no objective rules for translating the results into a course of action.
- MCS is a forward-looking technique, based on distributions of input parameters. With resolution of uncertainty and managerial flexibility, the distributions of critical parameters may change. MCS fails to capture such changes.

5.4 Flaw of Averages

Savage [2000] gives a description of the Flaw of Averages by stating that “Plans based on the assumption that average conditions will occur are usually wrong”. Flaw of Averages is mathematically also known as Jensen’s Inequality which states that the expected values of a function may not be the same as the function of expected value. It can be mathematically expressed as follows:

$$E[F(x)] \neq F(E[x])$$

Where $F(x)$ is a function of variable x and $E[x]$ is the expected value of variable x.

The importance of simulations is best explained in situations defined by *flaw of averages*. When dealing with uncertain variables like interest rate, demand growth rate, revenues etc. MCS can be employed to generate probabilistic distributions which imitate real-life scenarios. Then instead of calculating outcomes based on expected values, managers can make decisions based on the distribution of outcomes – both expected mean and extreme values.

5.4.1 Example

Consider a simple cash flow of \$100,000 each year for 3 years from today. The discount rate for all three years may be 2, 5, 8% with equal probability.

Table 5.2: Flaw of Averages Example

Rate (%)	**2**	**5**	**8**
NPV (\$)	288,388	**272,325**	257,710

NPV at average discount rate of 5% is \$272,325 whereas the average of NPV values calculated using all three discount rates is \$272,807. The outcome according to expected input parameter is not the same as the expected value of outcome.[15] Expected-input based NPV disregards the outcomes if unexpected discount rates prevail. Whereas input and output distribution based expected NPV heeds to the consequences of unexpected discount rates also.

5.5 Value-at-Risk

Value-at-Risk (*VaR*) is a statistical or probabilistic risk measure that is particularly helpful in capturing potential downside losses. *VaR* was first introduced in context of financial markets. Financial institutions measure and manage risk exposure on own behalf and on behalf of their clients. Later the same concept was translated into risk evaluation for capital investment.

To understand *VaR* in terms of project finance, consider that a project loses X amount in a particular year. Given the distribution of all possible annual losses over recent period let there be only x percent probability that annual losses will exceed X. It is equivalent to stating that $VaR_{x\%}$ of the project is X.

[15] The exception to Flaw of Averages is observed when the expected value of variable x may be expressed as a linear combination of uncertainty in the distribution of variable x. Consider $F(x) = 2x$. In this case $E[F(x)] = F(E[x])$.

When ROA is conducted by the *Simulation Method* (See Section 5.2.1.1 and 5.3), the distribution of results can also be viewed from *VaR* perspective (See Section 6.5.3). The probability density and cumulative distribution functions help in computing *VaR*.

5.5.1 Probability Density and Cumulative Distribution Functions

The Cumulative Distribution Function (cdf) is the probability that a random variable *X* takes a value less than or equal to *x*. That is

$$F(x) = \Pr[X \leq x] = \alpha$$

For a discrete distribution, this can be expressed as

$$F(x) = \sum_{i=0}^{x} f(i)$$

Where $f(i)$ is the Probability Density Function (pdf) for a discrete random variable *X*

$$f(x) = \Pr[X = x]$$

5.6 Simple Examples of Real Options

ROA is best understood with the help of a few examples by comparing alternatives with and without any options.

5.6.1 Option to Defer

This is a simple but realistic business case underlining the importance of optionality in the hands of an active and rational management. Suppose that the management has two alternatives to invest $1 million to manufacture a new product. [16]Annual returns are predicted to be uncertain with expected mean (R_M) equal to 15% if demand grows at the forecasted rate. The alternatives are:

1. No Option: Invest today (year zero).

[16] The following example is based on Myers, S., Brealey, R. (2003) "*Principles of Corporate Finance*" (7th Ed.), Real Options 22, pp. 622-624.

2. Option: Observe demand and defer investment by a year (invest in year one).

Assume that the hurdle rate of the project is 12%, firm's WACC is 10% and risk-free rate is 8%.

Valuation of Alternative 1: No Option

The expected cash flows are shown in Figure 5.2.

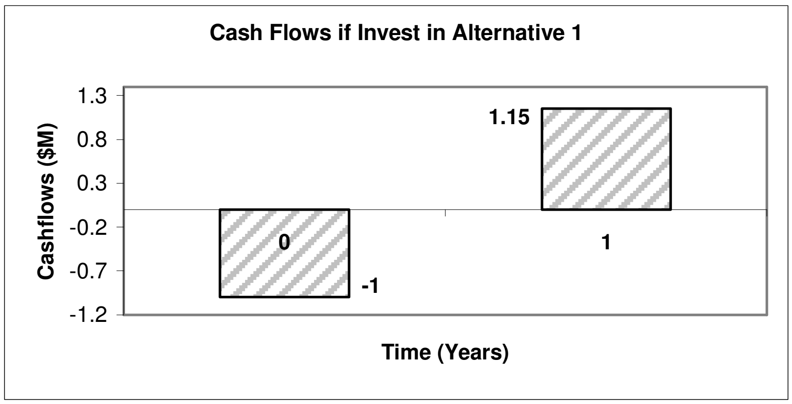


Figure 5.2: Cash Flows in Alternative 1 with No Option

Discounting cash flow in year 1 at WACC

$$NPV = \frac{1.15M}{(1.12)^1} - 1M = \$26{,}786$$

Valuation of Alternative 2: Option to Defer

The management can choose to defer the $1 million for maximum of one year. Though they lose the profits in year one, they can ascertain whether demand will pick up or nose-dive. By waiting for a year, they discover that either of the two possible demand scenarios will occur: A high or low demand scenario, with returns of R_H = 30% and R_L = -5% respectively. For simplicity assume conservatively that the management does not invest the money anywhere from year zero to one. Figure 5.3 and 5.4 illustrate the cash flows in both the demand scenarios if the management defers investment.

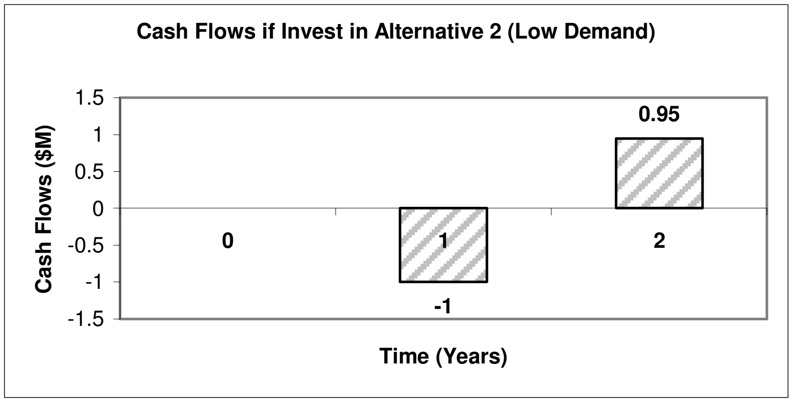


Figure 5.3: Cash Flows in Alternative 2 (Low Demand Scenario)

The cash flows are discounted to year one at the project hurdle rate (12%) and to year zero at WACC (10%).

$$NPV_{Year1} = \frac{0.95M}{(1.12)} - 1M = -\$151,786$$

$$NPV_{Year0} = \frac{-\$151,786}{1.1} = -\$137,987$$

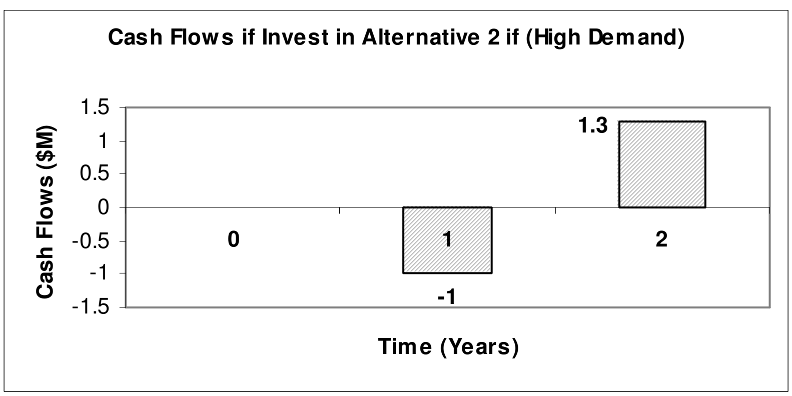


Figure 5.4: Cash Flows in Alternative 2 (High Demand Scenario)

$$NPV_{Year1} = \frac{1.3M}{(1.12)} - 1M = \$160,714$$

$$NPV_{Year0} = \frac{\$160,714}{1.1} = \$146,104$$

The negative NPV in the low demand scenario should deter the management from investing anything in such a situation, thereby driving NPV in low demand scenario to 0.

Some commonly mistaken concepts:

- The difference between the NPV in high demand scenario and the NPV in alternative 1 should not be confused as the value of the option to defer.
- The probability of occurrence of high and low demand scenario does not affect the *option* value, but affects the *expected mean NPV* in alternative 2. The consequences of two cash flow scenarios impact the option value via the *risk-neutral probability* measure.

Assuming that this option can be valued by the no arbitrage approach, using the binomial method: First step is to calculate the *risk-neutral probability* (RNP) (See Section 5.2.1.1) of high and low demand in the risk-neutral world. In the risk-neutral world, the expected return should equal the risk-free rate. Let p be the RNP of high return.

$$E[return] = (30) * p + (-5) * (1 - p) = 8\%$$

$$\therefore p = 0.371$$

The cash flows from both the scenarios in alternative 2 are discounted back at the risk-free rate and weighted by the risk-neutral probability of each scenario to obtain the option value. It is already shown that if the demand is low, the cash flow is zero since the management should not undertake the project. In the high case:

$$DCF_{Year0}^{Risk-free} = \frac{1.3M}{(1.08)^2} - \frac{1M}{(1.08)} = \$188{,}615$$

Option Value = \$188,615*0.371 + \$0*(1 – 0.371) = \$69,976

The option value being greater than NPV in alternative 1, the management should keep the option open till year 1, which implies that it is beneficial to defer the project for a year. Table 5.3 presents a sensitivity analysis on R_M, R_H, R_L as defined in the above example (Risk-free rate is assumed to be 8% in all cases). The first row recapitulates calculations and results for the case explained in detail above.

Table 5.3: Sensitivity Analysis on Option Value

R_M (%)	R_H (%)	R_L (%)	NPV Alt 1 ($)	NPV Alt 2 (High) ($)	NPV Alt 2 (Low) ($)	RNP	Option Value ($)	Decision
15	30	-5	26,786	146,104	(137,987)	0.371	69,976	Defer
15	20	-5	26,786	64,935	(137,987)	0.520	53,498	Defer
15	30	5	26,786	146,104	(56,818)	0.120	22,634	Build Today
10	30	-5	(17,857)	146,104	(137,987)	0.371	69,976	Defer
10	20	-5	(17,857)	64,935	(137,987)	0.520	53,498	Defer
10	30	5	(17,857)	146,104	(56,818)	0.120	22,634	Defer
20	30	-5	71,429	146,104	(137,987)	0.371	69,976	Build Today
20	25	5	71,429	105,519	(56,818)	0.150	21,862	Build Today
20	30	5	71,429	146,104	(56,818)	0.120	22,634	Build Today
20	40	-5	71,429	227,273	(137,987)	0.289	79,287	Defer

The intuition from this example and sensitivity analysis is summarized as follows:

- Positive (negative) NPV is not a sufficient condition for the decision to invest (not invest) in any risky project. There might be better alternatives: Wait and see.
- If the expected returns of investing in year 0 are significantly high (20%), it is beneficial to capture the cash flows as soon as possible and it is advisable to exercise the option right away by investing today (unless the future cash flows in year 1 are found to be vastly divergent from the forecasted cash flows in year 0).
- If the expected returns of investing in year 0 are low (10 or 15%) and the future outcomes are uncertain, then higher potential gains or prevention of wealth erosion make it worthwhile to wait and observe.

5.6.2 Option to Expand or Contract

The option to *expand* an existing project is akin to what managers consider "*riding gains*" and option to *contract* is similar to *"cutting losses"*. If a financial proposition shows favorable prospects after an investment is made, then management may choose to increase the scale of investment or invest in similar alternatives. If the investment does not appear profitable, the management can potentially prevent further wealth erosion by unwinding their position. In terms of project finance, in promising scenario, management may choose to increase the scale of operations in existing facilities or develop similar facilities to augment production. In worse case scenario, management might choose to sell-off or shut down the project (completely or partially).

Example of Option to Expand

In manufacturing facilities offering economies of scale gains, capacity planning follows the conventional deterministic approach as explained in Chapter 4. This example shows that there might be a better alternative: A flexible capacity planning approach. One could compute the value of the option to expand as in Section 5.6.1 by the assumption of no arbitrage approach; nevertheless it is tough to justify that the cash flows of any manufacturing facility can be replicated by a portfolio of loans and financial assets to enforce the no-arbitrage options pricing approach. The importance of this example is firstly to initiate the idea of flexibility in capacity planning paradigm and illustrate how the provision to adapt to uncertain outcomes allows managers to manage risk and increase the expected NPV of projects. Secondly, decision-making should be based on the distribution of inputs and consequences in accordance with risk-preferences, rather than the expected input based NPV.

Assume that the management has 2 alternatives to invest in a manufacturing factory producing an essential necessity. It is an important pre-requisite that the management is obliged to satisfy demand at all times. Current demand of 50,000 units is forecasted to increase by 10% per year but this growth rate is subject to uncertainty. Demand could increase by 15% or 5% with equal probability (expected average growth is 10%).

1. No option – Management does not recognize risk of demand uncertainty and proceeds according to forecasts: Install a plant today of 80,000 unit capacity at cost of $150,000.[17]
2. Option to expand – Management recognizes risk of demand uncertainty and proceeds with a flexible plan: Install a plant today of 65,000 unit capacity at cost of $130,000 and add an incremental capacity of 15,000 at the cost of $50,000 at any time over the next three years if demand exceeds 65,000 units.

Assume Weighted average cost of capital (WACC) = 12% and Unit profit = $1

What should be the management's strategy?

Valuation of Alternative 1

Forecasted installed capacity, demand and cash flows[18] over the 4 years are tabulated below (cash flows in U.S. dollars).

Table 5.4: Alternative 1 with No Option

Year	0	1	2	3	4
Capacity	-	80,000	80,000	80,000	80,000
Forecasted Demand	-	50,000	55,000	60,500	66,550
Cash Flows	(150,000)	50,000	55,000	60,500	66,550
Discounted Cash Flows	(150,000)	44,643	43,846	43,063	42,294
NPV	**23,845**				

The NPV is calculated by discounting back all the cash flows at WACC (12%). If the management has faith in demand forecasts as shown in Table 5.4 then the strategy to

[17] The costs are calculated using a power function to recognize economies of scale in construction (Cost in USD ≅ 101.23*Capacity^0.647)

[18] Annual Cash flow = Annual Demand*$1 – Installation Investment in that year (operational costs are assumed to be negligible). Production begins in year 1 and the profits for each year are booked at the end of the year.

expand would require installations in year 0 and 4, leading to an NPV of $12,069. Conventional methodology suggests that the alternative to build one large plant is better due to gains from economies of scale in construction.

Valuation of Alternative 2

From experience or domain knowledge, it was established that in reality the annual demand could grow by 15% or 5% with equal probability, instead of the 10% as forecasted. The lattice representation of demand growth in Figure 5.5 helps understand probabilistic demand distribution over the next 3 years.

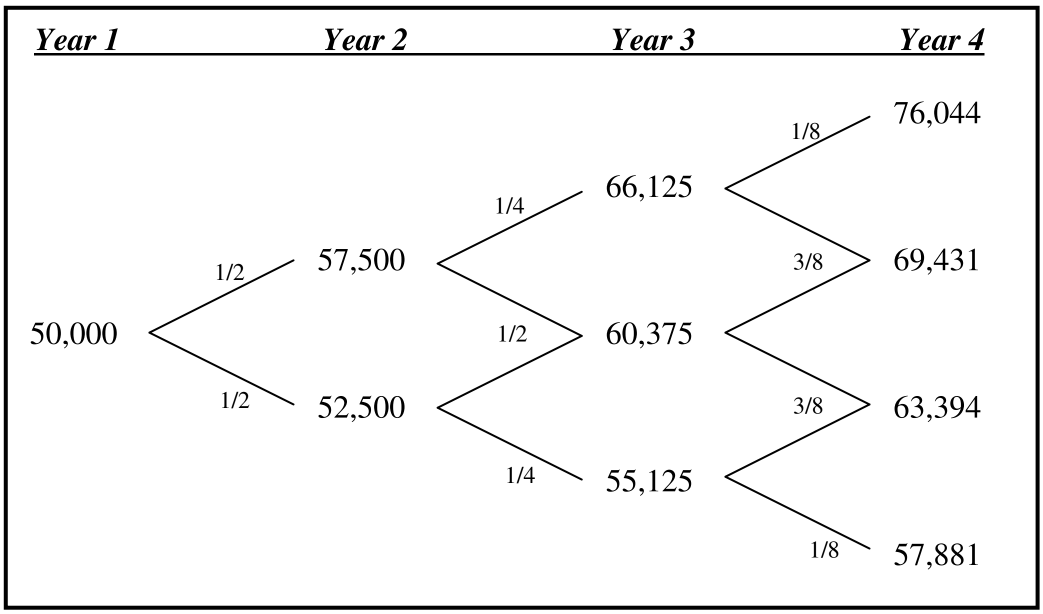


Figure 5.5: Demand Growth Binomial Lattice

In this lattice, demand could increase by 15% or 5% at each node, written as the values at *up* and *down* nodes in the following year. Such a lattice covers all possible demand scenarios.[19] The sequence of values from first to the last node corresponds to a single demand scenario and is also called a *path.* It is a *path dependent* lattice, as opposed to the

[19] Such lattices in which there are only 2 outcomes at each node such that 2 nodes may lead to the same outcome in up and down case in the subsequent year are called Recombining Lattice.

lattice discussed in Section 5.2. In a *path dependent* lattice, the value at each consecutive node is a function of the value at the previous node. An example of *path independent* lattice is that representing stock price distribution. Stock price at time *t* is considered to be independent of price at time *t-1*.[20] The same lattice can also be generated via Monte Carlo Simulations (Section 5.3). For 100 simulations, see the frequency of occurrence above each demand value in Figure 5.6. Divide the frequency by number of simulations (100) to get the probabilities of occurrence, which are approximately the same as the theoretical values in Figure 5.5.

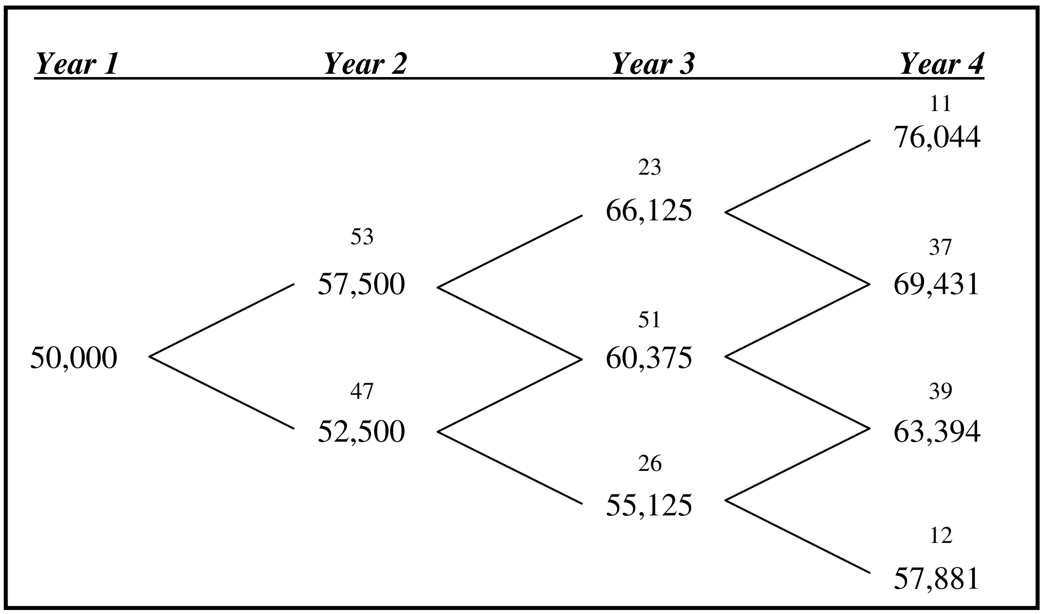


Figure 5.6: Demand Lattice Generated by Monte Carlo Simulations

The values at all the nodes in the same year constitute the distribution of demand for that year. For instance, in year four, the range of demand distribution is 20,163 units (76,044 – 55,881). The expected average of distribution in each year corresponds to the forecasted values for demand shown in Table 5.4.

[20] This is based on the assumption that market is *semi strong* efficient.

Table 5.5: Alternative 2 with Option to Expand

	Years	0	1	2	3	4
up-up-up	Capacity	-	65,000	65,000	80,000	80,000
	Demand	-	50,000	57,500	66,125	76,044
	Cash Flows	(130,000)	50,000	57,500	16,125	76,044
	PV	(130,000)	44,643	45,839	11,477	48,327
	NPV	**20,286**				
up-up-down	Capacity	-	65,000	65,000	80,000	80,000
	Demand	-	50,000	57,500	66,125	69,431
	Cash Flows	(130,000)	50,000	57,500	16,125	69,431
	PV	(130,000)	44,643	45,839	11,477	44,125
	NPV	**16,084**				
up-down-up	Capacity	-	65,000	65,000	65,000	80,000
	Demand	-	50,000	57,500	60,375	69,431
	Cash Flows	(130,000)	50,000	57,500	60,375	19,431
	PV	(130,000)	44,643	45,839	42,974	12,349
	NPV	**15,804**				
up-down-down	Capacity	-	65,000	65,000	65,000	65,000
	Demand	-	50,000	57,500	60,375	63,394
	Cash Flows	(130,000)	50,000	57,500	60,375	63,394
	PV	(130,000)	44,643	45,839	42,974	40,288
	NPV	**43,743**				
down-up-up	Capacity	-	65,000	65,000	65,000	80,000
	Demand	-	50,000	52,500	60,375	69,431
	Cash Flows	(130,000)	50,000	52,500	60,375	19,431
	PV	(130,000)	44,643	41,853	42,974	12,349
	NPV	**11,818**				
down-up-down	Capacity	-	65,000	65,000	65,000	65,000
	Demand	-	50,000	52,500	60,375	63,394
	Cash Flows	(130,000)	50,000	52,500	60,375	63,394
	PV	(130,000)	44,643	41,853	42,974	40,288
	NPV	**39,757**				
down-down-up	Capacity	-	65,000	65,000	65,000	65,000
	Demand	-	50,000	52,500	55,125	63,394
	Cash Flows	(130,000)	50,000	52,500	55,125	63,394
	PV	(130,000)	44,643	41,853	39,237	40,288
	NPV	**36,020**				
down-down-down	Capacity	-	65,000	65,000	65,000	65,000
	Demand	-	50,000	52,500	55,125	55,881
	Cash Flows	(130,000)	50,000	52,500	55,125	55,881
	PV	(130,000)	44,643	41,853	39,237	35,513
	NPV	**31,246**				

Table 5.5 includes all the eight possible demand scenarios, total capacity and annual cash flows. Starting from 50,000 in Figure 5.5, all the eight paths are traced by *up* or *down* movement of demand in subsequent years[21].

Results

The project has positive NPV in all the 8 possible demand scenarios. (Range: $11,818 to $43,743; expected mean: $26,845; $VaR_{50\%}$: $20,286).

- The expected mean obtained in alternative 2 is higher than the expected mean in the alternative 1.
- The downside risk and upside potential are higher in the alternative 2. (i.e. the minimum and maximum expected NPV in alternative 2 are lower and higher than the expected NPV in alternative 1).
- The expected NPV in alternative 1 is higher than that in alternative 2 in 4 out of 8 scenarios (when demand grows consistently grows at a high rate). If demand grows at a moderate or below expected rate, then alternative 2 is better on NPV basis due to cost-savings from installing a smaller plant.

There is no unique answer to the preferable strategy because it is contingent on management's objectives, risk-tolerance and their expectations of demand growth. An aggressive management interested in increasing upside gains or expected mean might choose alternative 2, whereas a more conservative management sensitive to downside risks may prefer alternative 1.

The intuition behind this simple example is that management might have ignored the flexible alternative if they proceeded along the lines of conventional capacity

[21] Shaded cells indicate capacity expansion and required investment of $50,000 in that period. The cost of additional plant is booked at the end of the year in which it was installed.

planning and valuation methodology. On conducting ROA, the management is better acquainted with the risk of uncertainty. Their decision will be sensitive to the entire spectrum of outcomes, instead of just the expected outcomes.

5.7 Capacity Expansion Option in Tunnels

This section demonstrates the applicability of ROA to analyze an option *in* project when the system design incorporates flexibility. Though a more detailed application to capacity planning in hydropower is developed later, the example in this section focuses on similar issues in tunnel construction. Tunnels and dams have similar cost-profiles: large irreversible upfront investments and marginal operational costs. They benefit from economies of scale in construction and face the constraint of changing initial design specifics (dam height or tunnel diameter) to expand capacity of existing facilities. This section examines the benefits of the flexibility to build small tunnels on a need-only basis as opposed to building large tunnels to realize benefits from economies of scale.

5.7.1 Uncertainty in Tunneling

Apart from the system-wide demand uncertainty, tunneling poses project-specific uncertainty. In spite of exhaustive remote sensing information and forecasts, the impact of geologic conditions, environmental phenomenon, human and material factors on excavation and support methods can not be assessed precisely till construction begins. These factors imbue uncertainty in tunnel advance rates, completion time and construction costs.

5.7.2 Tunnel Construction Time and Cost Estimates

The uncertainty of tunnel construction costs and time is best expressed as a Time-Cost Scattergram (Figure 5.7).

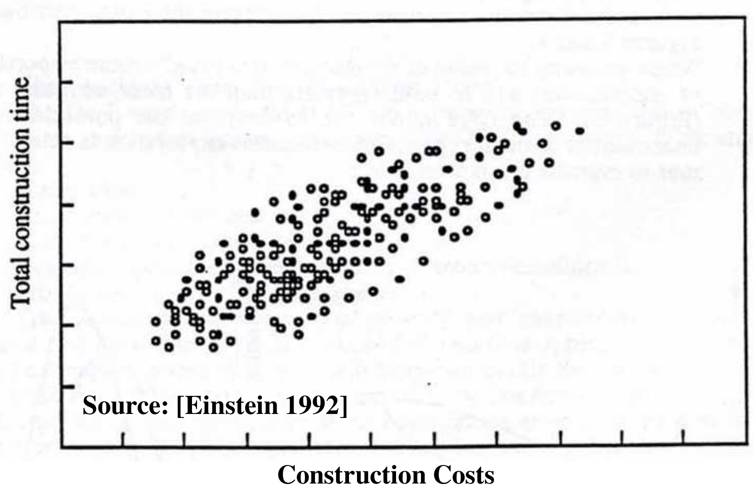


Figure 5.7: Time-Cost Scattergram for Tunnel Construction

The time and cost of different tunneling systems serving similar purposes can differ severely. Specifically, Figure 5.8 depicts schematic of three tunnel systems for the Gotthard-Basetunnel; Figure 5.9 plots their time-cost Scattergram [Einstein 1992].

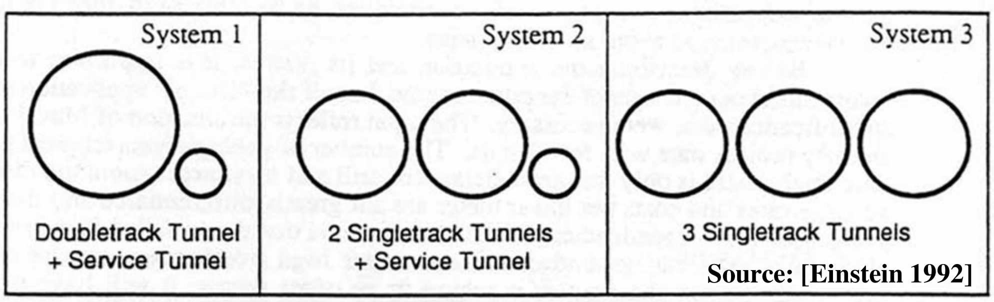


Figure 5.8: Schematic of the Three Systems for the Gotthard-Basetunnel

The modification of design parameters affects decision-making criteria:

- ***Construction Time:*** It depends on the slowest project component. In System 1 the slowest component is the double track tunnel. The same single-track tunnel is the slowest component in systems 2 and 3 therefore these appear to have similar construction times on the time-cost Scattergram.

- ***Construction Cost:*** Unlike time, costs accumulate. With an increasing number of major components, the cost of the system escalates. Therefore, the costs of the 3 systems in decreasing order: System 3, 2 and 1.

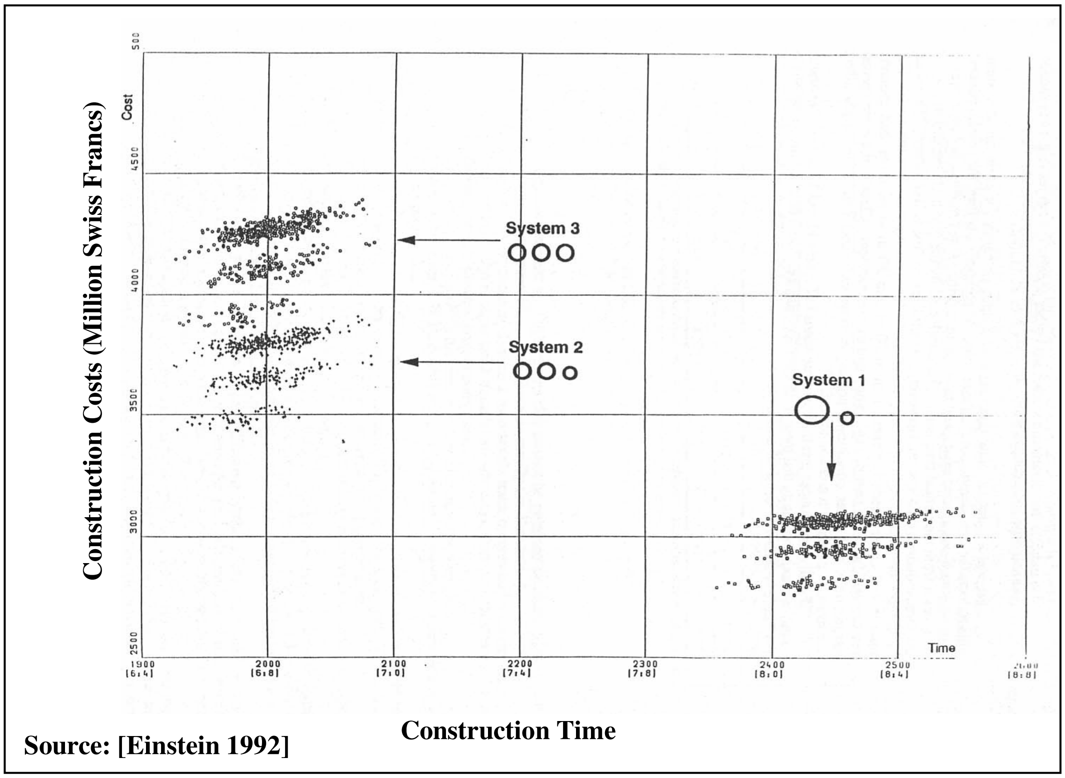


Figure 5.9: Time Cost Scattergram of the Three Systems

(Time in working days and year months; 1 year = 300 working days)

The current practice is to explore if "bad-ground" exists, and treat the zone prior to the tunnels reaching it, which removes it from the critical time path. Figure 5.9 shows three separate clouds or bands for each tunnel system. The lowest cost cloud represents zero length of "bad-ground" i.e. it involves only construction and exploration costs. The middle and upper clouds represent 1 to 20 m and 20 to 50 m of "bad-ground" respectively, with the costs of exploration and treatment in addition to construction costs.[22]

- ***Time Value of Money:*** There is greater change in cost of construction related to a change in time of construction for shorter duration projects like System 2 and 3 compared to the longer duration System 1.

5.7.3 Economies of Scale in Tunneling

Empirical studies suggest that there are *economies of scale* benefits in the tunnel construction costs (Economies of Scale discussed in Section 4.4.2). Data from 50 tunnel projects was collected and various adjustments were made to account for factors such as inflation etc [Einstein 1999a]. A best-fit line (2nd order curve with zero intercept) is shown in Figure 5.10 and the relation between cost per linear foot of tunnel (in USD) and diameter (D) of the tunnel is computed as:

$$Cost = 10.281D^2 - 2.836D + 362.7 \qquad \textbf{\textit{Equation 5.2}}$$

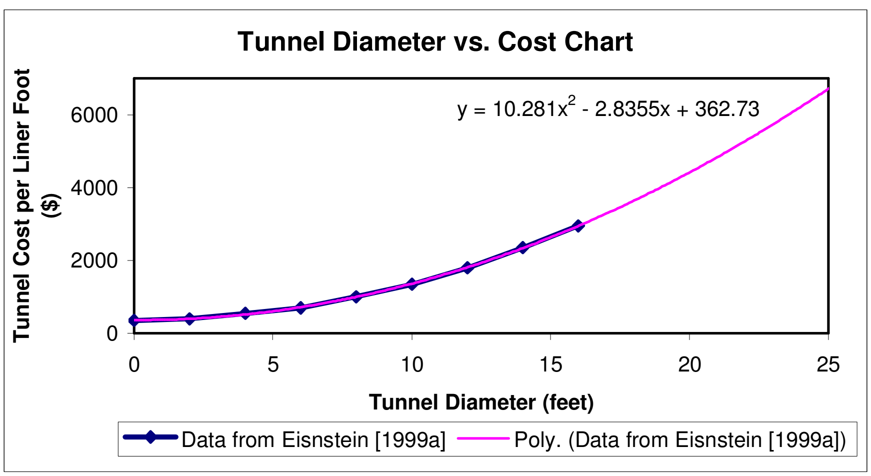


Figure 5.10: Tunnel Diameter vs. Cost Chart

[22] The cost-time bands in Figure 5.10 appear to be nearly parallel to the cost axis indicating that there is little time dependence.

Cursory inspection of Equation 5.2 does not directly indicate economies of construction because it is typically established by a cost-capacity relation like Equation 4.1. The capacity of a tunnel (x_c) can be expressed in equivalent terms as power producible from that tunnel. Although Equation 5. 3 and 5.4 numerically relate the tunneling parameters; the interdependence of various factors on diameter (especially empirical factors) makes it difficult to derive an exact relation between capacity and diameter. An empirical relation establishing that cost per unit capacity is a decreasing function of tunnel diameter is sufficient to establish economies of scale in tunnel construction. Borrowing figures from the analysis in Section 5.7.8, the cost per unit capacity for 2 different tunnels has been charted against their diameters in Figure 5.11.

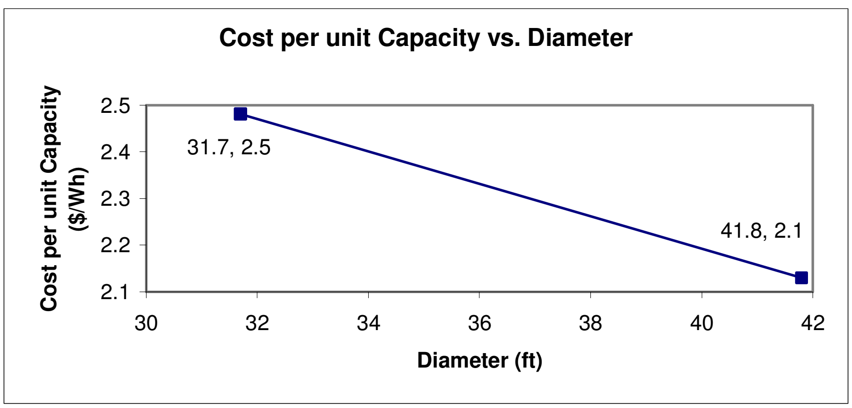


Figure 5.11: Cost per Unit Capacity vs. Tunnel Diameter

Based on the figure above, it is concluded that there are economies of scale in tunnel construction.

5.7.4 Case: Construction Costs of Two Tunneling Alternatives

Typically tunnel construction is governed by benefits accruing from economies of construction, therefore current practice is to build tunnels of large diameters far in advance of demand equaling installed capacity. This case study examines the merit of constructing smaller tunnels with the *flexibility* to expand in future on a need-only basis.

Suppose the management's objective is to construct tunnels for hydropower generation and that they are faced with two alternatives for as depicted in Figure 5.12.

- System 1 is a set of 2 same sized tunnels: Management can construct these tunnels sequentially. Hence, if significant demand does not materialize, they have the *option* of not constructing the second tunnel.
- System 2 is a single tunnel which leads to same hydropower generation as both the tunnels combined in System 1.

The mean expected demand requires the construction of both the tunnels in System 1. To generate the same amount of hydropower, if the net water head from point A to B is the same for both the systems, overall head loss should be similar in both the systems (assuming that the net volume of water passing through both the systems per unit time is the same). The assumption about same hydropower generation in both the systems is essential for a fair comparison of both the systems.

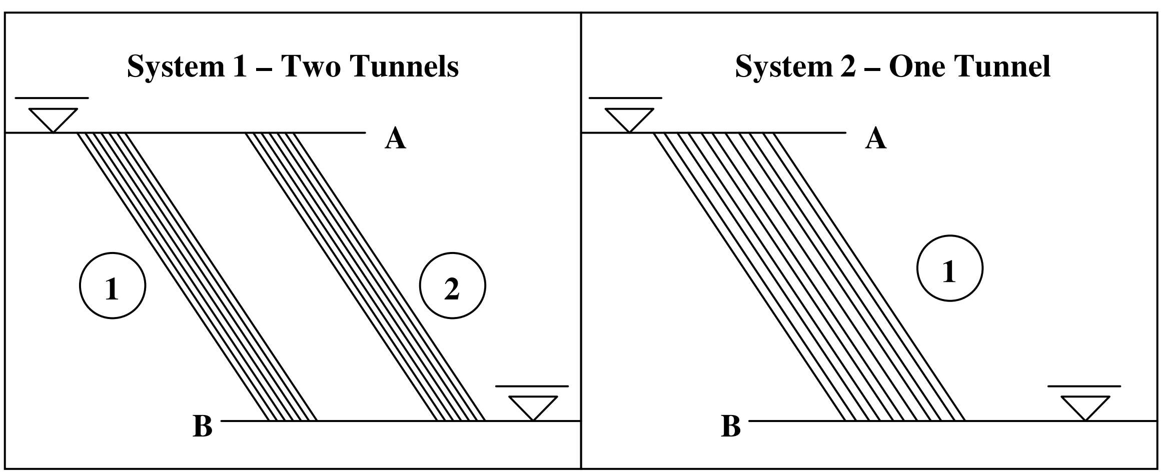


Figure 5.12: Schematic of Equivalent Tunnel Systems

For realistic analysis, the dimensions of System 1 are picked from an actual 2 tunnel system in the Sichuan Hydropower Project [SHHI 2002]. The dimensions of System 2 are defined by a single tunnel posing similar head losses as System 1. Some helpful fluid mechanics concepts are listed for reference.

5.7.5 Fluid Mechanics Concepts

Fully Developed Turbulent Flows: Flows are classified as laminar or turbulent, based on the Reynolds Number [Young 2001]. Reynolds Number should be approximately less than 2000 for laminar flow and greater than 4000 for turbulent flow. Turbulent flow is a complex topic – one that has yet defied a rigorous theoretical treatment. Thus most turbulent pipe flow analyses are based on experimental data and semi-empirical formulas.

Gross Head: It is the total fall or difference between the elevation of water surface in the diversion pond and in the lower end of tail race (Difference between points A and B in Figure 5.12).

Net Head: It is gross head minus total head loss in conduits and tail race. Losses within turbine casing, the turbine and draft tube are normally not included in conduit losses, but charged against turbine efficiency.

Head Loss: The head loss can be categorized into major and minor head losses. Only major head losses are considered in this study. The pressure drop and head loss in a pipe depend upon the wall shear stress (τ) between the fluid and pipe surface. In the case of turbulent flows in particular, the shear stress is a function of the density of fluid (water in our case). The pressure drop (ΔP) is a function of the following variables:

$\Delta P = f(v, D, l, \varepsilon, \mu, \rho)$

v - Average velocity (m/s)

g – Acceleration due to gravity (= 9.8 m/s^2)

D, l - Diameter and length of pipe (m)

ε - Measure of roughness of pipe

μ, ρ - Viscosity (kg/m-s) and density (kg/m^3) of fluid

Empirical Factors

Reynolds Number (Re) = $\rho\ v\ D/\ \mu$

Relative Roughness = ε/D

f – Friction Factor = F$(Re, \varepsilon/D)$

Using semi-empirical formulae and dimensional analysis, it may be determined that head loss in meters (h_L) is given by the *Darcy-Weisbach equation* (Equation 5.3). It is valid for any fully developed, steady, incompressible pipe flow – whether the pipe is horizontal or on a hill [Saleh 1962]:

$$h_L = \frac{flv^2}{2Dg}$$ ***Equation 5.3***

It is not challenging to nail down theoretical dependence of the friction factor on Reynolds Number and relative roughness. In practice, the information is derived empirically condensed into the *Moody Chart.*

Energy and Power: If certain volume of water in a storage reservoir is allowed to pass through the turbines under a constant net head, the energy delivered in the form of work is given by Equation 5.4 [Saleh 1962].

$$K = \rho_w V(H - h_L)e$$ ***Equation 5.4***

K = Energy (kg-m)

ρ_w = Density of water (kg/m^3)

V = Volume of water (m^3)

H = Gross head of water (m)

e = Plant efficiency (fraction)

Equation 5.4 can be modified as follows to calculate power (W):

$$W = \rho_w A v (H - h_L) e \qquad \textbf{\textit{Equation 5.5}}$$

A = Cross-section area of tunnel (m^2)

5.7.6 System 1 – Two Tunnel System

This is a system of two tunnels of with same design parameters. As mentioned before, the data is same as that for a two tunnel system in the Sichuan Hydropower Project [SHHI 2002].[23]

Data Assumptions

Number of Tunnels = 2

Water temperature = 20^{o}C

ρ_w = Density of water at 20^{o}C = 998.2 kg/m^3

μ_w = Viscosity of water at 20^{o}C = 1.002 E-3 kg/m-s

v_1 = Velocity of water = 4.5 m/s

H = Total head of water = 280 m

D_1 = Diameter and l_1 = length of each tunnel = 9.6 m and 19409 m respectively

Material of construction – Concrete

Measure of roughness for tunnel constructed from concrete - 0.001 m

Calculations

$$\mathrm{Re}_1 = \frac{\rho_w v_1 D_1}{\mu} = 4.31E7$$

(Re_1 well qualifies this flow as wholly turbulent)

[23] The parameters specific to System 1 and 2 are distinguished by subscript 1 and 2.

$$\text{Relative roughness} = \frac{\varepsilon}{D_1} = 1.04E-4$$

f_1 = Friction factor = 0.012 (for above values of Re_1 and relative roughness from Moody Chart [Young 2001])

Inputting all the values in Equation 5.3:

$$h_L = \frac{f_1 l_1 v_1^2}{2 D_1 g} = 25.06m$$

5.7.7 System 2 – Equivalent One Tunnel System

Simplifying assumptions

For both the Systems:

1. Operational costs and overhead expenses are comparable.
2. Assumed same: method of construction, labor wages, equipment costs, tunnel length, construction material, environmental and functional conditions and the volume of water passing through the tunnels.

Calculations

The head loss between both systems is equated for finding the diameter of single equivalent tunnel. The critical factors to be determined for System 2 are: f_2, v_2, D_2. Since f_2 depends upon v_2 and D_2, the tunnel diameter and velocity via an iterative process. Smallest diameter satisfying this constraint is selected to minimize tunnel costs.

From the assumption that the same amount of water passes through both tunnels systems per unit time:

$$\pi R_2^2 v_2 = 2 * \pi R_1^2 v_1$$

$$\pi \frac{D_2^2}{4} v_2 = 2 * \pi \frac{D_1^2}{4} v_1 = 2 * \pi \frac{9.6^2 * 4.5}{4} = 651.7 \text{ m}^3/\text{s}$$

$$\therefore D_2^2 v_2 = \frac{651.7}{\pi} * 4 = 829.4 \text{ m}^3\text{/s} \qquad \textbf{Equation 5.6}$$

The diameter and velocity in System 2 are tied by Equation 5.6. A sensitivity analysis on diameters vs. velocity is helps in finding the relationship between D_2, v_2, Re_2, f_2. For any chosen diameter, Equation 5.6 gives the corresponding velocity value. Table 5.6 exhibits Reynolds No, Relative Roughness and Friction Factor for combinations of D_2 and v_2.

Table 5.6: Sensitivity Analysis for Calculating Dimensions of System 2

Diameter (m)	Velocity (m/s)	Reynolds No x (E+07)	Eq Roughness x (E-05)	Friction Factor x (E-03)
10	8.29	8.28	10.00	12
11	6.85	7.53	9.09	12
12	5.76	6.90	8.33	12
13	4.91	6.37	7.69	12
14	4.23	5.91	7.14	11
15	3.69	5.52	6.67	11
16	3.24	5.17	6.25	11
17	2.87	4.87	5.88	11
18	2.56	4.60	5.56	11
19	2.30	4.36	5.26	11
20	2.07	4.14	5.00	11

The sensitivity analysis proves that the flow lies in the wholly turbulent region, so friction factor is independent of tunnel parameters. Therefore friction factor for System 2 is selected as 0.012.

Data Assumptions

H = Total head of water = 280 m (Same as for System 1)

l_2 = Length of Tunnel = 19409 m (Same as for System 1)

Material of construction – Concrete (Same as for System 1)

Measure of roughness for tunnel constructed from concrete - 0.001 m

f_2 = Friction Factor = 0.012 (See Above)

Calculations

The head loss in both the systems has to be the same: **25.06** m

$$h_L = \frac{f_2 l_2 v_2^2}{2 * D_2 g} = \frac{0.012 * 19409 * v_2^2}{2 * D_2 * 9.8} = 25.06 \text{ m}$$

$$\therefore \frac{v_2^2}{D_2} = \frac{25.06}{11.88} = 2.11$$ ***Equation 5.7***

From Equations 5.6 and 5.7, D_2 and v_2 are solved to be 12.66m and 5.15 m/s respectively. Table 5.7 shows another method (numerical) of computing these values – empirically finding the head loss for various combinations of D_2 and v_2 and choosing the combination which gives a head loss closest to 25.06 m

Table 5.7: Empirically Determining Dimensions of System 2

Diameter (m)	Velocity (m/s)	Reynolds No x (E+07)	Eq Roughness x (E-05)	Friction Factor x (E-03)	Head Loss (m)
10.00	8.29	8.28	10.00	12	81.72
11.00	6.85	7.53	9.09	12	50.74
12.00	5.76	6.90	8.33	12	32.84
12.65	5.18	6.54	7.91	12	25.23
12.66	5.17	6.54	7.90	12	25.13
12.67	5.17	6.53	7.89	12	**25.03**
12.68	5.16	6.53	7.89	12	24.93
12.70	5.14	6.52	7.87	12	24.74
13.00	4.91	6.37	7.69	12	22.01
14.00	4.23	5.91	7.14	11	15.20
15.00	3.69	5.52	6.67	11	10.76

From both the analytical and numerical method, the dimensions of System 1 are chosen as Diameter = 12.67 m and velocity = 5.17 m/s.

5.7.8 Capacity Planning Alternatives

The cost and power delivered by individual tunnel in both the systems is found by Equations 5.2 and 5.5 (Costs in Table 5.8 are for the entire tunnel length):

Table 5.8: Cost and Power for Systems 1 and 2

	Diameter (ft)	Cost (M$)	Power (MWh)
System 1	31.7	206	83
System 2	41.8	353	166

The merit of both alternatives can be measured by 2 metrics: mean and distribution of expected costs.

The expected demand at the time of commissioning both the systems is such that it would require construction of both the tunnels in System 1 or equivalent tunnel in System 2. Given the demand uncertainty, Table 5.9 lists certain scenarios of power requirement and corresponding costs for both the systems.

Table 5.9: Costs of both Systems for Various Power Requirement Scenarios

Power (MWh)	System 1		System 2		Cost Savings in Sys 1 over 2 (%)
	# Tunnels	Cost (M$)	# Tunnels	Cost (M$)	
100	1	206	1	353	72
150	2	412	1	353	-14
200	3	617	2	707	14
250	4	823	2	707	-14
300	4	823	2	707	-14
350	5	1,029	3	1,060	3

Demand drives the cost distribution in both the alternatives but it is evident that if demand does not materialize significantly, there are significant gains of building small tunnels on a need-only basis.

Instead of viewing demand at the time of commissioning only, one could look at incremental demand over the next few years. In that case, the tunnels in both the systems will be built sequentially and the results are compared on DCF basis. Assume that present demand is 100 MWh and it grows by 50 MWh in every 5 years.

Table 5.10: DCF of both Systems for Various Power Requirement Scenarios

Year	Power (MWh)	System 1		System 2		Cost Savings in Sys 1 over 2 (%)
		# Tunnels	DCF (M$)	# Tunnels	Cost (M$)	
0	100	1	206	1	353	72
5	150	2	367	1	353	-4
10	200	3	493	2	570	16
15	250	4	592	2	570	-4
20	300	4	592	2	570	-4
25	350	5	653	3	675	3

At 5% discount rate, Table 5.10 lists the discounted costs for each system. The cumulative probability distribution curve in Figure 5.13 translates the same results in a visual format.

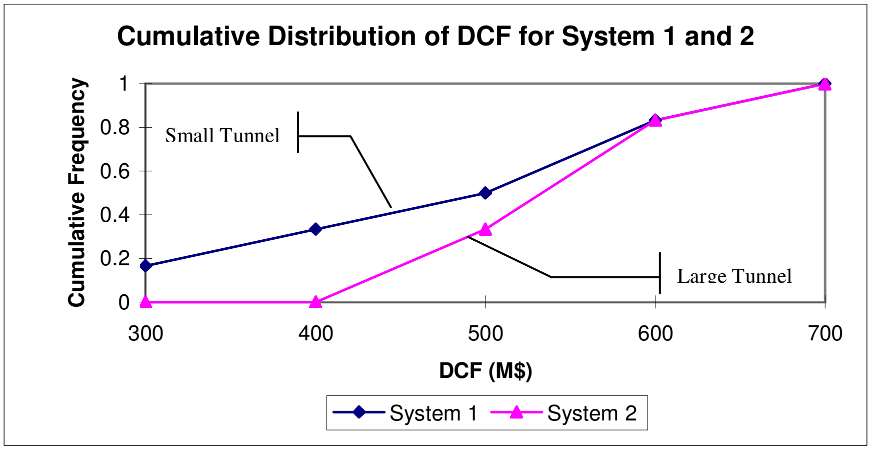


Figure 5.13: Cumulative Distribution of DCF for System 1 and 2

Figure 5.13 verifies that the management does much better with System 1 when the demand is low with potential tradeoffs when the demand increases significantly.

The purpose of ROA in this case is not to suggest a well-defined strategy for the management but give them the opportunity to recognize and address risk due to uncertainty. ROA allows management to incorporate flexibility in system design so that it may respond in the most cost effective manner for various possible demand outcomes, instead of just the expected mean outcome. Having conducted ROA, the management can not only control the cost distributions, they are in a position to choose a strategy better aligned with their future expectations and risk preferences.

6 Hydropower Capacity Planning

This chapter presents an advanced framework for hydropower capacity planning built on the foundation of generic capacity planning concepts initiated in Chapter 4. This framework lays the foundation for comparing ROA and conventional DCF as valuation and strategic decision-making tools in hydropower capacity planning. First, existing *deterministic* models are examined. Sensitivity and scenario analyses unearth their shortcomings. Then a simulation-based *probabilistic* model developed in Microsoft Excel is discussed. This user-friendly model allows the management to account for uncertainty in growth rate of electricity demand and enables them to compare results of conventional and ROA. The comparative results of deterministic and probabilistic models ascertain *effectiveness* of the probabilistic approach.[24] Finally the alternatives with and without the *option* to vary size and timing of construction along with the *option* to defer construction by relying on oil-fired plants are compared (introduced in section 1.3). The conclusion is that probabilistic approach scores over static approach on all the performance metrics. Flexible, option-based alternatives often pose better expected outcomes; more importantly, they allow the management to alter the distribution of outcomes in accordance with their risk-preferences.

6.1 Hydropower Capacity Planning Framework

The framework in this Chapter is derived from Hreinsson's [2000] work in Icelandic hydropower sector. He developed capacity planning models for a single and sequence of hydropower plants based on Manne's [1961] and Chenery's [1952] work. His approach is

[24] All costs in Hreinsson's deterministic and probabilistic model developed in this study are expressed in million 1990 Kronur (ISK). ISK100.17 = $1. This is to facilitate a comparison between both the approaches because Hreinsson's results are expressed in 1990 ISK. These figures can be escalated by approximately 35% for today's levels although the primary interest of this study is a relative comparison of cost figures.

representative of actual practice in hydropower engineering and planning. He has addressed the issue of optimal plant sizing and sequencing in hydro-based power systems. Unlike his predecessors who primarily focused on benefits of economies of scale while determining optimal plant size, he proposes the concept of *Actual Utilization Cost* (AUC) (explained in Section 6.2.1.2) and concludes that it is economically more efficient to operate smaller plants at higher utilization capacity than large plants at low utilization capacity while waiting for the demand to materialize.

Nonetheless, just like his predecessors, Hreinsson does not recognize the risk due to variance of forecasts. His models are also *deterministic* since he assumes constant growth rate for demand. His basic model is presented in section 6.2. A *probabilistic* model developed on the same lines, which recognizes the risk of demand uncertainty is presented in section 6.3.

6.2 Hreinsson's Deterministic Model

According to Hreinsson [2000], there are 2 types of deterministic models: for satisfying *basic demand* only; for satisfying *basic* and *extra demand*.

- ***Basic Demand (BD)***: It is the market related demand which must be satisfied at all times. No backlog is permitted. This may comprise but is not limited to residential and commercial demand, "light industry".
- ***Extra Demand (ED)***: Extra Demand is superimposed on the BD as a step-function. In many cases the decision maker has the option to serve the ED which consists of massive energy sales to Energy Intensive Industries (EII) or bulk energy export.

6.2.1 Basic Demand Model

6.2.1.1 Notation

i =1,2,...,N Index of individual hydroelectric plants. The plants are assumed to be constructed in the sequence indicated by this index.

Pl_i: i^{th} plant.

$D(t)$: A non-decreasing demand function for BD (expressed in GWh/year) extending indefinitely into the future. Throughout this chapter, $D(t) = qt$.

q: Constant growth rate of linear demand function (GWh/year/year).

t_i: Construction and/or start-up date of Pl_i.

r: Annual interest rate.

α: Continuous time discount rate.

C_i: Construction or investment cost for Pl_i. It embeds or ignores operations and replacement costs. It is assumed that this cost is incurred as a lump sum at the start-up date of Pl_i.

P_i: Discounted total cost of Pl_i and all following plants, the time reference of discounting being the start-up date for Pl_i.

E_i: Discounted energy of the BD to the start-up date of Pl_i.

F_i: Discounted energy of the future ED to the start-up date of Pl_i.

e_i: Discounted energy output of Pl_i allocated to the BD.

x_i: Capacity or size of Pl_i (e.g. in GWh/year).

y_i: Fraction of capacity or size of Pl_i devoted to serve ED (in GWh/year).

f_i: Discounted energy from Pl_i allocated to the ED.

k_{ai}: Actual Unit Cost (AUC) of Pl_i – cost per unit discounted energy output from Pl_i - accounting for the period of excess capacity.

k_{xi}: Actual Unit Energy Cost (AUEC) of Pl_i – average unit cost from this plant with partial utilization due to ED at the start-up of Pl_i.

k_{fi}: Full Utilization Cost (FUC) of Pl_i, or the unit cost from Pl_i with instantaneous full utilization of the plant capacity.

$z_i = \sum_{j=1}^{i-1} x_j$ Total accumulated capacity of all plants preceding Pl_i at the time when Pl_i is started.

6.2.1.2 Model

(The fundamentals of optimal capacity planning for a single plant are presented in Chapter 4.) It is assumed that in case of no ED, all the energy produced is devoted to BD and excess capacity remains under utilized till BD equals total installed capacity.

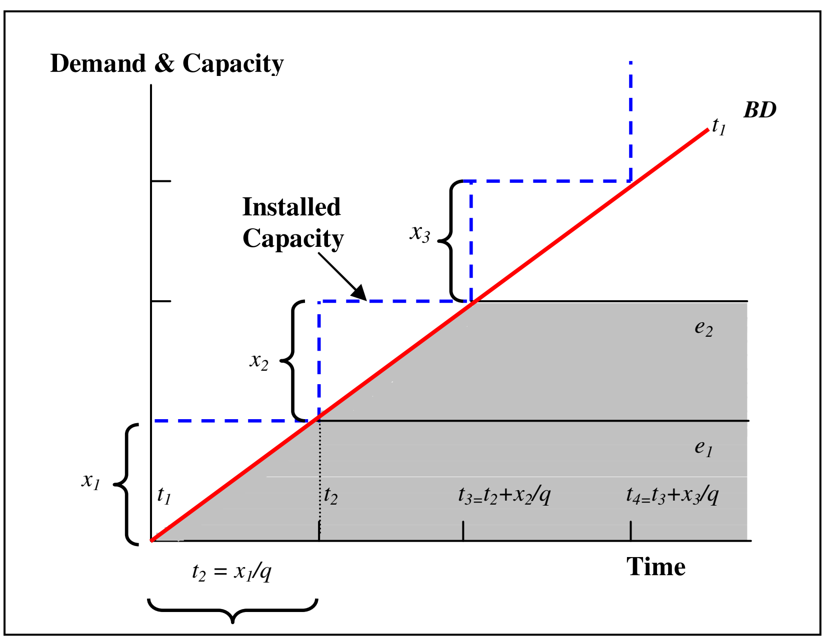


Figure 6.1: Basic Demand vs. Capacity [Hreinsson 2000]

Figure 6.1 depicts the evolution of BD defined by *D(t)* ($0 \le t < \infty$) and stepwise capacity expansion to satisfy the BD. Assuming that the demand grows at a deterministic linear rate, *D(t)=qt*. The total discounted cost of Pl_i and all the plants following its installation is given by Equation 6.1

$$P_i = C_i + P_{i+1}\exp(-\alpha(t_{i+1} - t_i)) \qquad \textbf{\textit{Equation 6.1}}$$

Where α is the continuous time discount rate defined derived from conventional annual interest rate *r*:

$$\alpha = \ln(1 + \frac{r}{100}) \qquad \textbf{\textit{Equation 6.2}}$$

Assuming a linear demand function, Equation 6.1 is rewritten as

$$P_i = C_i + P_{i+1}\exp(\frac{-\alpha(x_i - y_i)}{q}) \qquad \textbf{\textit{Equation 6.3}}$$

Consider installed capacity of Pl_i is x_i. As long as the BD is less than total installed capacity, the plant operates at under capacity and produces just enough energy to satisfy BD. When the energy demand crosses x_i at time t_{i+1}, Pl_i continues to produce at its full capacity for the rest of its design life and Pl_{i+1} is constructed to satisfy demand in excess of x_i. The total discounted energy produced by Pl_i (referred as e_i), to satisfy BD is expressed by Equation 6.4:

$$e_i = \int_0^{t_i} qt\exp[-\alpha t]dt + \int_{t_i}^{\infty} x_i \exp[-\alpha t]dt \qquad \textbf{\textit{Equation 6.4}}$$

$$= \int_0^{x_i/q} qt\exp[-\alpha t]dt + \int_{x_i/q}^{\infty} x_i \exp[-\alpha t]dt$$

$$= \frac{q}{\alpha^2}\left(1 - \exp\left[\frac{-\alpha x_i}{q}\right]\right)$$

For instance Pl_1 with installed capacity x_1 satisfies qt from time period t_1 to t_2. At time t_2 the demand catches up with installed capacity. Thereafter Pl_2 satisfies all BD in excess of x_1 and Pl_1 continues to produce x_1 amounts of energy for the rest of its life to satisfy BD. The construction cost of Pl_i (C_i)is given by Equation 6.5:

$$C_i = ax_i^b \qquad (0<b<1) \qquad \textbf{\textit{Equation 6.5}}$$

Equation 6.5 implies economies of scale in hydropower plant construction. Simply stated, it means that the cost of construction increases at a slower rate than capacity size (See also Section 4.4.2). No adjustment is made for inflation as costs and discount rate are measureds in real Kronurs.

For comparing the financial feasibility of plants with different sizes, it is not sufficient to compare the cost of construction only. It is important to define the concept of *Actual Unit Cost* (AUC) of energy. AUC is the total cost of Pl_i per unit of discounted energy output for Pl_i. Hreinsson concludes that optimal plant size should be determined by lowest AUC instead of simply lowest cost of construction. Since this model accounts for BD only, Equation 6.6 expresses the total cost of Pl_i per unit of discounted energy produced by this plant to satisfy BD, e_i:

$$AUC = k_{ai} = \frac{C_i}{e_i} = \frac{\alpha^2 a x_i^b}{q\left[1 - \exp\left(\frac{-\alpha x_i}{q}\right)\right]} \qquad \textbf{\textit{Equation 6.6}}$$

Figure 6.2 shows AUC_i as a function of various installed capacity sizes x_i (same assumptions for input parameters as in Hreinsson's [2000] calculations q=60GWh/year/year; a=80 Mkr; b=0.77; α=5%).

Comparison of Figure 6.2 and Figure 4.3 highlights an interesting result. Both the figures plot graphical calculation of optimal capacity size: first by Hreinsson's AUC approach and second by Manne's DCF approach. The curve is steeper on left hand side in Figure 4.3 and on the right hand side in Figure 6.2.

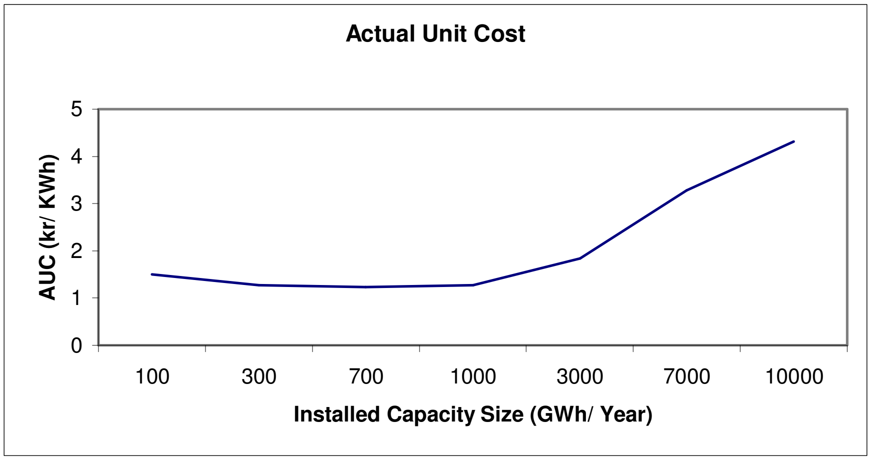


Figure 6.2: AUC as a function of Total Installed Capacity and (No Extra Demand)

DCF approach only minimizes total cost of installation regardless of capacity utilization – It is more sensitive to undercapacity due to gains from economies of scale in larger plant sizes; AUC approach seeks to minimize the cost of electricity produced per unit cost of installed capacity – it is more sensitive to overcapacity due to higher costs associated with under-utilization of resources. This marks a fundamental difference between both the design approaches. It is not sufficient to build huge facilities to book cost savings if they remain under-utilized in future. AUC approach is deemed favorable because it incorporates gains from economies in the light of percentage capacity utilization.

6.2.2 Basic Demand with Extra Demand Model

Now consider the addition of ED on existing BD. ED is known with greater certainty than BD because normally the involved parties enter into binding contracts in advance. Economic efficiency is enhanced on AUC basis if certain energy production is devoted to ED as it helps in harnessing gains from economies, which would be otherwise lost if BD grows at a relatively slow rate.

Referring to Figure 6.3, the construction of all subsequent facilities after the first one is advanced in time by a factor of y_i/q, compared to the case when there is no ED. For example, Pl_1 satisfies BD equal to qt ($t_1<t<t_2$) and ED equal to y_1 till the time of construction of new plant at $t_2 = (x_1-y_1)/q$. From t_2 onwards, it operates at its full capacity and produces x_1 units of energy.

The discounted energy produced by Pl_i associated with BD and ED (shaded areas in Figure 6.3) is given by Equation 6.7 and Equation 6.8 respectively:

$$e_i = \int_0^{(x_i-y_i)/q} (qt + y_i)\exp(-\alpha t)dt + \int_{(x_i-y_i)/q}^{\infty} x_i \exp(-\alpha t)dt \qquad \textbf{Equation 6.7}$$

$$f_i = \int_0^{\infty} y_i \exp(-\alpha t)dt = \frac{y_i}{\alpha} \qquad \textbf{Equation 6.8}$$

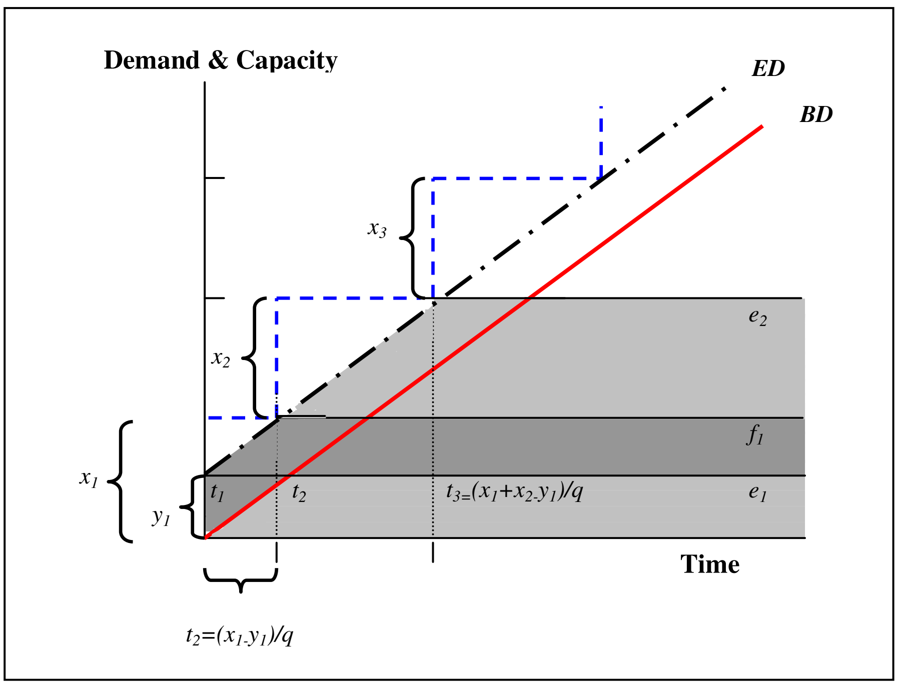


Figure 6.3: Basic and Extra Demand vs. Capacity [Hreinsson 2000]

Similar to the definition of AUC is the concept of *Average Unit Energy Cost* (AUEC). It is a more generalized expression of AUC accounting for ED as well.

AUEC k_{xi} for Pl_i in general case:

$$k_{xi} = \frac{\alpha^2 C_i}{\alpha y_i + q(1 - \exp\left[\frac{-\alpha(x_i - y_i)}{q}\right]} \qquad \textbf{\textit{Equation 6.9}}$$

In the special case when ED is zero ($y_i = 0$), AUEC is same as AUC and Equation 6.9 reduces to Equation 6.6.

$y_i = x_i$ marks another special case. This means that the plant operates at full utilization capacity right from the point of installation. In this case AUEC is renamed as *Full Utilization Cost* (FUC):

$$FUC = \frac{\alpha C_i}{x_i} \qquad \textbf{\textit{Equation 6.10}}$$

6.2.2.1 Results and Conclusions

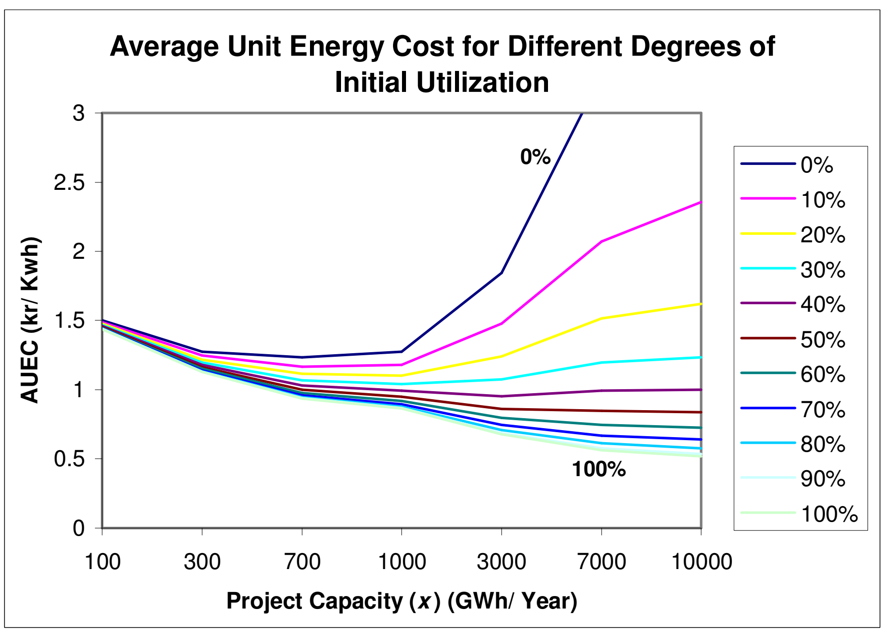


Figure 6.4: AUEC for Different Degrees of Initial Utilization

Figure 6.4 is a regeneration of Hreinsson's graphical depiction of AUEC as a function of installed capacity size for different levels of initial capacity utilization (y_i). [Input parameters q=60 GWh/year/year; a=80 Mkr; b=0.77; α=5%]. It conveys that the lower the initial utilization of the plant, the smaller the optimal plant size. As the initial utilization percentage increases to 100%, large plants are financially more feasible because of economies of scale and instant utilization of installed capacity.

This figure also shows the benefits of building plants of smaller capacity and expanding on a need-only basis if the demand grows substantially. Consider a demand of 4900 units.

- ***Alternative 1***: Operate a plant of size 7000 units at 70% initial utilization capacity. AUEC = 0.66 kr/KWh.
- ***Alternative 2***: Operate a plant of size 10000 units at 49% initial utilization capacity. AUEC = 0.83 kr/KWh.

Based on the Hreinsson's conclusion of choosing plants with least AUEC, it is preferable to build small plants and operate them at high load capacity right from the beginning as opposed to building large plants to book gains from economies, which remain under-utilized for extended periods.

6.2.2.2 Sensitivity Analysis

So far, the analysis assumed a constant demand growth rate, as if both ED and BD are known with certainty, which is not the case in reality. Sensitivity analysis illustrates the impact of demand uncertainty on AUEC for different degrees of initial utilization. The basic demand growth rate q was expected to be 60GWh/year/year in the deterministic case. AUEC is recomputed for both higher and lower than expected values of q [20 and 100 GWh/year/year]. Figure 6.5 graphs the results of variable demand growth rate for different percentages of ED. These graphs corroborate some of the previous conclusions:

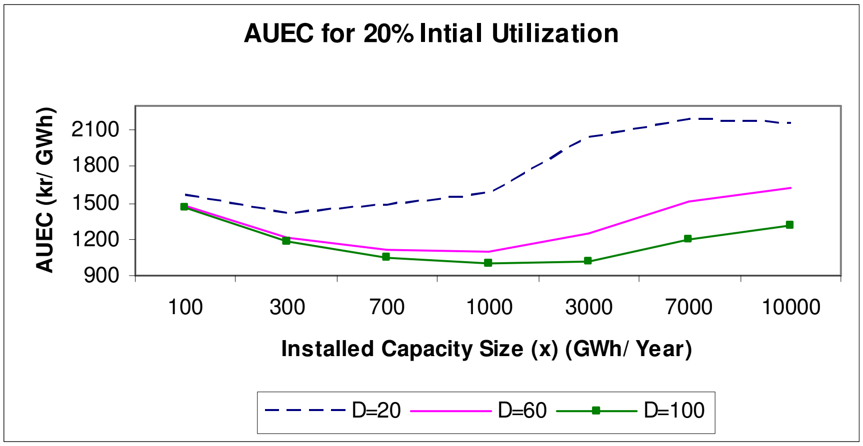


Figure 6.5a: AUEC at 20% Initial Utilization for Various Demand Growth Rates

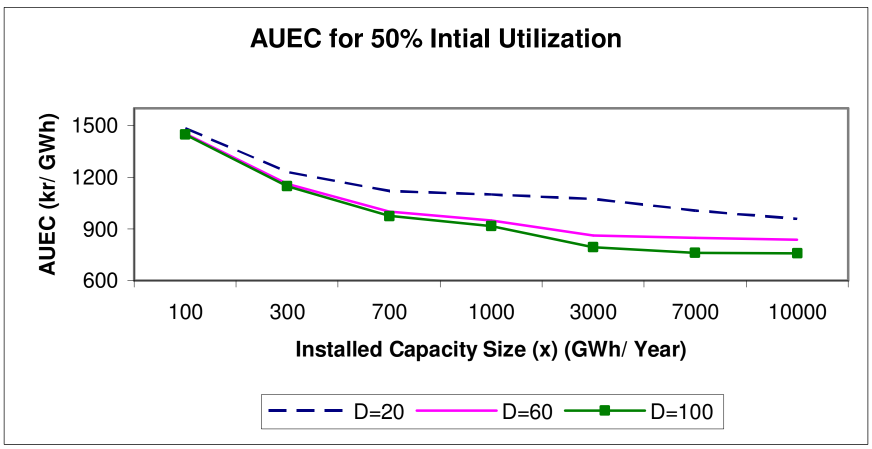


Figure 6.5b: AUEC at 50% Initial Utilization for Various Demand Growth Rates

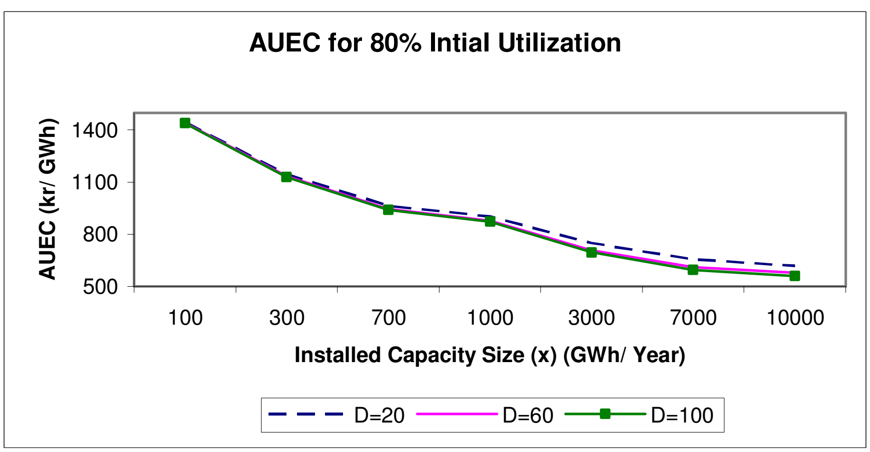


Figure 6.5c: AUEC at 80% Initial Utilization for Various Demand Growth Rates

- Optimal plant size is sensitive to demand growth rate, therefore demand uncertainty should be recognized.
- Lower than expected demand growth rate leads to higher AUEC: underutilization of plants for longer periods than those planned for leads to lost revenues. This can be avoided by building smaller plants.
- The lower the initial utilization, the effect of demand uncertainty is more pronounced: At higher initial utilization levels, the AUEC is nearly the same for all levels of installed capacity. Extra demand helps in reducing revenue uncertainties and leads to economically efficient use of hydropower facilities.

The sensitivity analysis shows possible outcomes if demand increases linearly at different rates. However in reality, demand does not grow at a constant rate, it is subject to uncertainty. The probabilistic model developed below addresses this issue.

6.3 Probabilistic Model

This Section presents a user-friendly *probabilistic* model developed in Microsoft Excel (See Appendix B) on the same lines as Hreinsson's deterministic model (Section 6.2). Unlike the deterministic model, the probabilistic model recognizes uncertainty in the growth of electricity demand. Instead of assuming a linear rate of growth, the probabilistic model simulates a realistic distribution of demand growth rate via Monte Carlo simulation technique (refer to Section 5.3). The analytical framework and definition of terms is same as that defined in Section 6.2 remain the same. It allows the user to examine various combinations of cost function, BD, ED, plant size and interest rates. It compares the results of conventional planning approach based on linear demand forecasts and the flexible planning approach based on simulated demand. A time horizon of 100 mimics the long design life of hydropower plants.

6.3.1 Generating Simulated and Forecasted Demand

6.3.1.1 Simulated Demand

On examining trends in hydropower electricity demand, the demand growth rate was found to follow a uniform distribution instead of the constant value assumed in deterministic models. In the probabilistic model, the user is given the flexibility to simulate uniform distribution of year-to-year demand growth rate according to a step function. (See Appendix A for detailed example on setting up Monte Carlo Simulations in Microsoft Excel). A single simulation generates 100 year-to-year demand growth rates according to the following inputs:

q: The linear rate at which demand grows in the deterministic model

q_u, q_d: The maximum and minimum permissible demand growth rate repectively

p_u: The probability with which simulated demand growth rate is between q_u and q

p_d: The probability with which simulated demand growth rate is between q and q_d

Example inputs: q = 30GWh/year/year; q_u = 50GWh/year/year; q_d = 10GWh/year/year; $p_u = 0.5$; $p_l = 0.5$;

Output of single simulation: Out of 100 year-to-year growth rates, 50 (= p_u*100) year-to-year demand growth rates are distributed uniformly between 50 and 30 GWh/year/year and 50 (= p_d*100) year-to-year demand growth rates are distributed uniformly between 30 and 10 GWh/year/year. 1000 such simulations are conducted and the average of year-to-year demand growth rate for each year is taken to be representative of actual demand growth.

If q is the average of q_u and q_d and $p_u = p_d = 0.5$, then the demand growth calculated using the average of 1000 simulations appears similar to the constant growth rate demand scenario. The medium growth case will possibly contain a few outliers in which the demand grows rapidly or at a very slow pace. It is essential to study the results of both the deterministic and probabilistic capacity planning models in case of such extremities. Instead of identifying the outliers among 1000 simulations for the average case, the model allows the user to construct consistently high and low demand scenarios. This can be achieved by adjusting the inputs in the model as shown below:[25] The simulated demand growth rates in all three cases are shown in Figure 6.6.

- High: $q = 30$; $q_u = 60$; $q_d = 0$ GWh/year/year; $p_u = 0.7$; $p_d = 0.3$;
- Medium: $q = 30$; $q_u = 60$; $q_d = 0$ GWh/year/year; $p_u = 0.5$; $p_d = 0.5$;
- Low: $q = 30$; $q_u = 60$; $q_d = 0$ GWh/year/year; $p_u = 0.3$; $p_d = 0.7$;

Figure 6.7 graphs the average of 1000 simulations for three scenarios of simulated demand (low, average (medium), high) and the linear forecast (only first 5 years shown for graphical clarity). The three demand growth scenarios should not be confused with EIA defined high, low, medium growth scenarios discussed in Chapter 3. EIA assumes a constant high, low or medium linear growth rate, without accounting for the risk of uncertainty. The high, low and medium growth scenarios generated by the probabilistic model are based on a probabilistic distribution of demand growth rate graphed in Figure 6.6, rather than naive adjustments to the linear growth rate.

[25] The high, medium and low demand scenarios in the remaining study refer to the input values shown here unless mentioned otherwise.

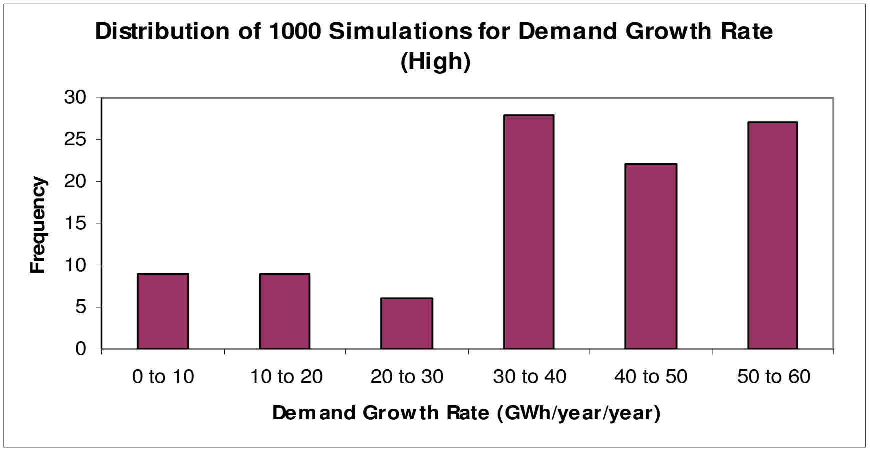


Figure 6.6a: Simulated Demand Growth Rates (High)

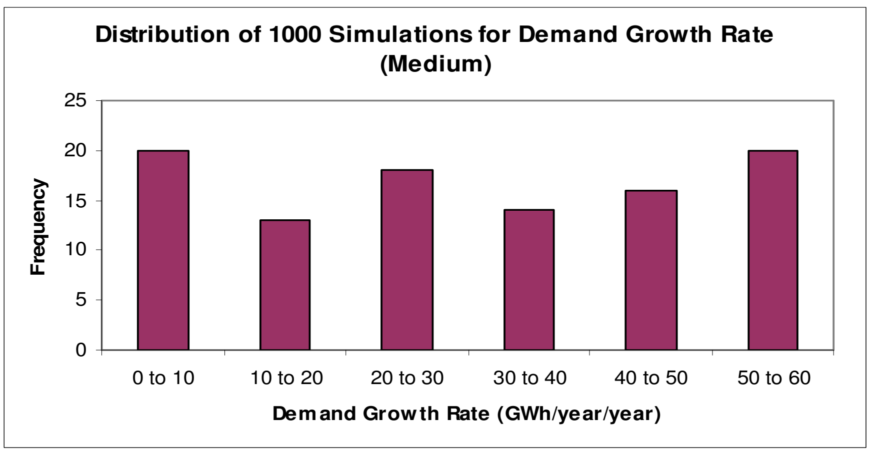


Figure 6.6b: Simulated Demand Growth Rates (Medium)

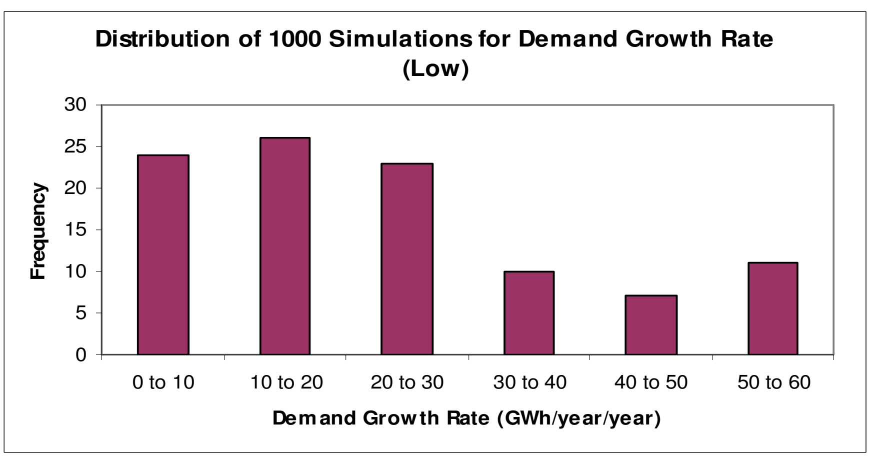


Figure 6.6c: Simulated Demand Growth Rates (Low)

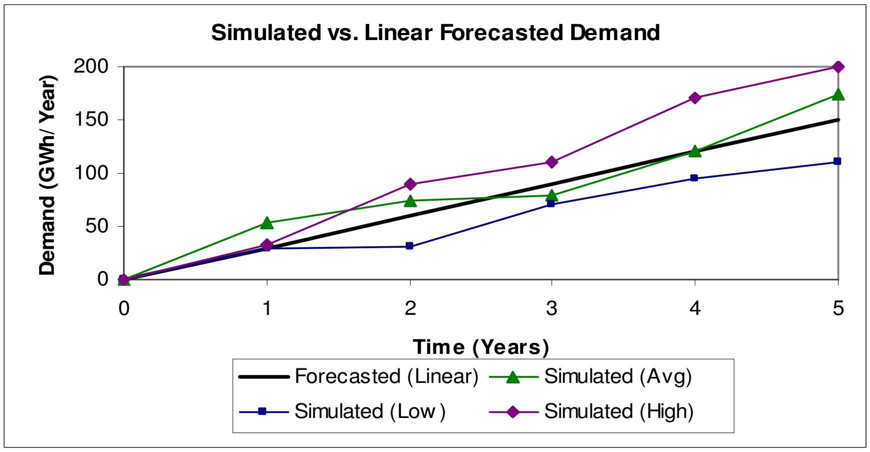


Figure 6.7: Simulated vs. Linear Forecasted Demand

6.3.1.2 Revised Linear Demand

The probabilistic model simultaneously computes results of deterministic and probabilistic approach for the same input parameters for ease of comparison. As in Hreinsson's models, the deterministic case in this model also assumes linear demand growth rate but it is unreasonable to assume that the forecasts will be disconnected from actual demand at the time of new forecasts, especially when previous forecasts have been deviating from actual values. It was noted in Chapter 3 that forecasts are revised when there is a measurable discrepancy between forecasted values and actual demand.

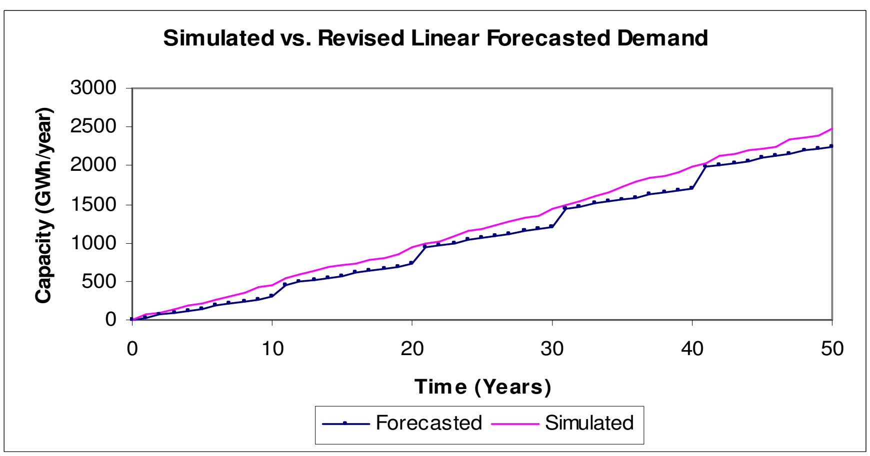


Figure 6.8: Simulated Vs Revised Forecasted Demand

The linear forecasts in the probabilistic model track simulated values and corrections are made to align them at the beginning of new decade if forecasts are consistently below or above the actual values for last 4 years of every forecast period. Figure 6.8 shows how this is achieved. In this case, the forecasts were consistently pessimistic, so they were aligned to the simulated demand at the beginning of each decade if the difference between forecasted and simulated values in the previous 4 years was greater than a user-specified value (5% in this case.). The user may choose not to revise the forecasts.

6.4 Determining Optimal Timing of Construction

The probabilistic model is designed to satisfy simulated demand at every instance of time. For an expected linear demand, the deterministic models fixes an optimal plant size x for the entire duration of project. These plants are constructed sequentially after every n^{th} year. This is called *static* capacity installation. In the probabilistic model also an optimal plant size is fixed for the entire duration of project but new construction is undertaken on a need-only-basis at flexible intervals. The optimal size minimizes the average of cost distribution for multiple demand scenarios (generated via Monte Carlo Simulation). This is called *dynamic* capacity installation (DCI). For mathematical simplicity, both the models suppose that a new facility can be constructed at will at a given instant of time. The time lag in construction is ignored because it does not change the relative comparison of results. In the probabilistic model, a new plant is constructed only if maximum possible annual demand exceeds the excess capacity from previously constructed facilities. For instance:

q = 30GWh/year/year; q_u = 50 GWh/year/year; p_u = 0.5; q_d = 10 GWh/year/year; = p_d = 0.5; Chosen plant size = 300 GWh/year

A new facility is constructed whenever excess capacity in the system is less than 50GWh/year, regardless of the simulated demand growth for the next year. This ensures that the system is always capable of satisfying demand. If demand exceeds forecasts, then it implies faster construction of new facilities and vice versa.

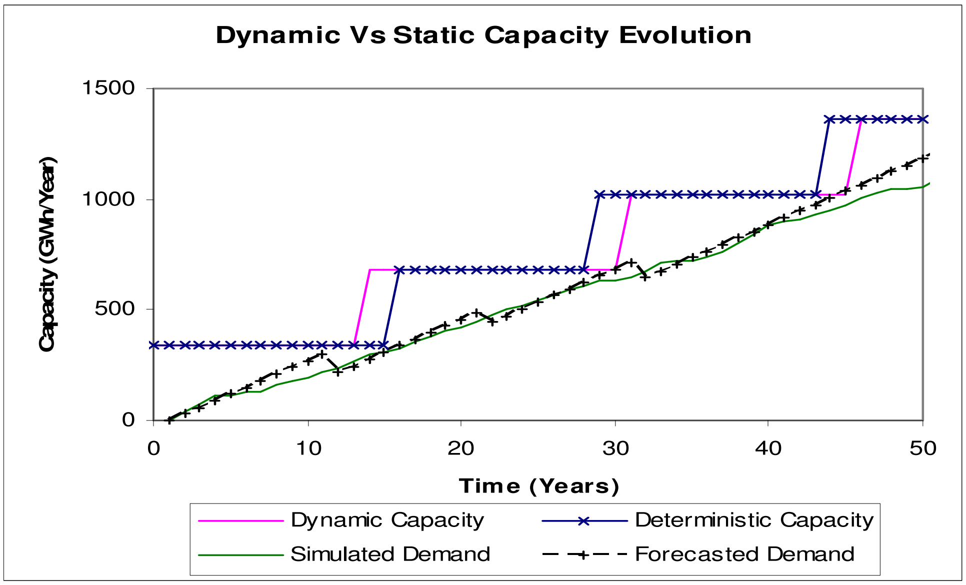


Figure 6.9: Dynamic Vs Static Capacity Evolution

Figure 6.9 shows dynamic vs. static capacity evolution in a case when forecasts were consistently optimistic (only 50 year horizon charted for graphical clarity). The steps indicate installation of a new facility. During the time horizon depicted in Figure 6.9, 4 plants of 300 GWh/year were installed in both cases; the installation was delayed in probabilistic model. The dollar amount spent in each case was the same (ignoring inflation); DCI gives lower total discounted costs due to time value of money.

6.5 Effectiveness of Probabilistic Model

As hinted in Chapter 1, the *effectiveness* of probabilistic and deterministic models is compared according to following three metrics, each described in greater detail in the following sections:

- Cost Efficiency
- Capacity Sufficiency
- Value at Risk

DCI is found to be more *effective* in cases when simulated and forecasted demand vary to a large extent. In case actual demand is somewhat similar to the forecasts, dynamic approach might not necessarily perform *better*.

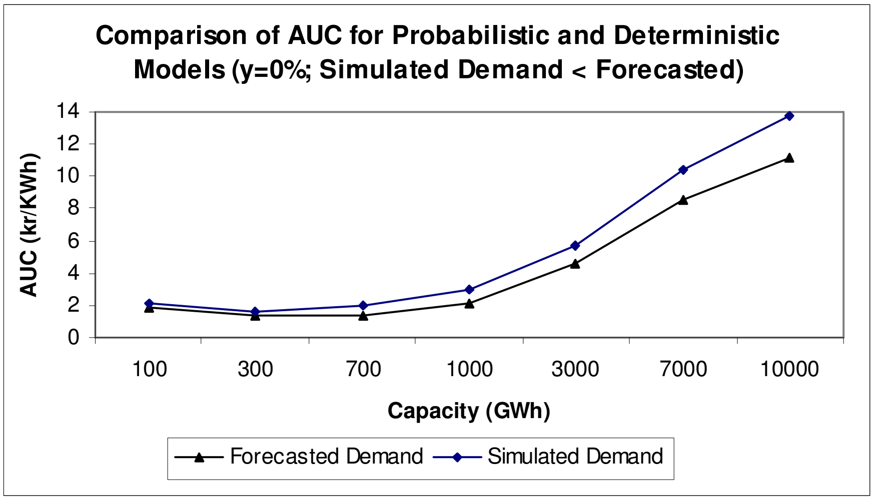
6.5.1 Cost Efficiency

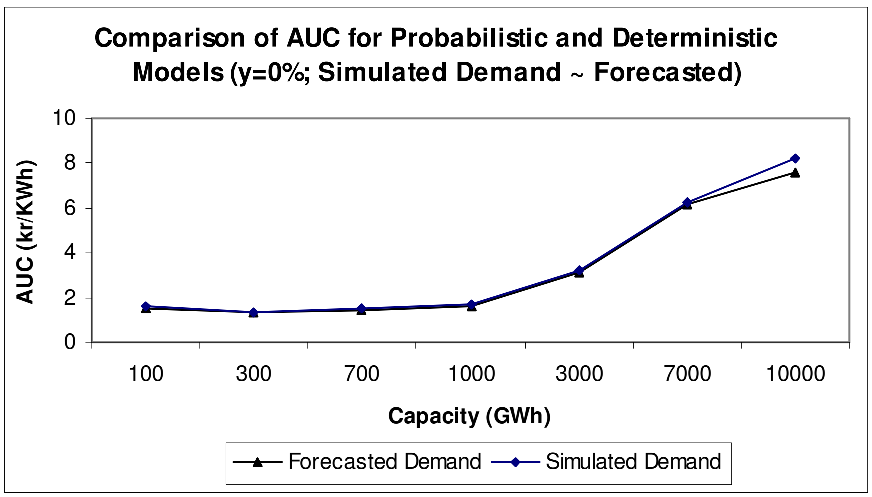
Hreinsson's concept of Actual Utilization Cost (AUC) is the metric used for comparing cost efficiency of probabilistic and deterministic models. DCI gives lower AUC due to two reasons:

1. Unless ED is more than 20% or simulated BD fast outpaces forecasts, probabilistic model recommends smaller optimal plant size (See Table 6.2).
2. Even if optimal plant size is the same in both approaches, new construction is delayed in case of demand uncertainty, especially if the actual demand is consistently below forecasts. Deferred construction of all successive plants prevents excess buildup of capacity and cost savings are realized due to time value of money.

Cost efficiency of probabilistic model is investigated for three demand scenarios: actual demand grows at higher than, lower than, similar to forecasted demand growth rate.[26] AUC is computed for each set of input parameters for each simulation (1000 times). Figure 6.10 graphs AUC (average of 1000 simulations) for the three scenarios as computed using the probabilistic and Hreinsson's deterministic model (using revised linear demand with q = 30GWh/year/year). ED is assumed to be 0% in all cases.

[26] Input parameters for generating simulated demand same as those in Section 6.3.1.1





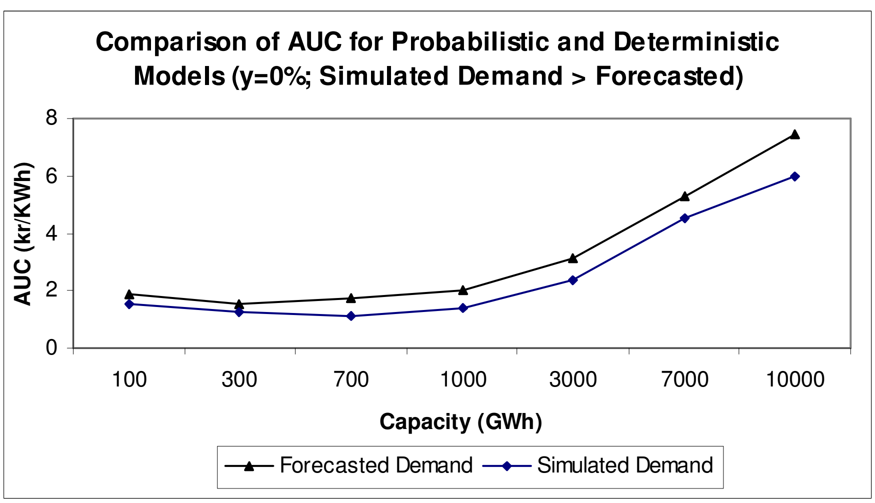


Figure 6.10: Comparison of AUC for Probabilistic and Deterministic Models

The same results are also tabulated in Table 6.1.[27] The least AUC for each scenario corresponding to capacity sizes listed in the table below are shaded.

Table 6.1: AUC using Probabilistic and Deterministic Model (kr/ KWh)

Capacity	Low Growth		Medium Growth		High Growth	
(GWh)	Simulated	Forecasted	Simulated	Forecasted	Simulated	Forecasted
100	2.123	1.843	1.612	1.535	1.512	1.913
300	1.601	1.323	1.343	1.336	1.258	1.522
700	2.007	1.350	1.487	1.458	1.319	1.730
1,000	2.981	2.098	1.665	1.624	1.388	2.008
3,000	5.726	4.544	3.219	3.143	2.374	3.134
7,000	10.360	8.543	6.258	6.192	4.534	5.321
10,000	13.746	11.089	8.253	7.610	5.996	7.432

Results

- Most important result is that both the probabilistic and deterministic models recommend a different optimal plant size. The results of a coarse investigation in Table 6.1 and Figure 6.10 exhibit the trend of AUC vs. capacity but do not indicate the optimal plant size (corresponding to least AUC). A finer analysis reveals the optimal plant size as advocated by 3 different approaches: Deterministic with linear demand forecasts (Hreinsson's model), deterministic with revised linear forecasts, probabilistic with simulated demand. Table 6.2 allows a comparison of these results:

Table 6.2: Optimal Plant Size by Various Planning Approaches

	Low		Medium		High	
	Opt Size	AUC	Opt Size	AUC	Opt Size	AUC
Constant Linear Demand	300	1.352	300	1.352	300	1.352
Revised Linear Demand	295	1.320	300	1.336	310	1.516
Simulated Demand	265	1.589	280	1.323	340	1.249

Even in the case the simulated demand is similar to the linear forecasts (medium), the optimal plant size by probabilistic approach is found to be smaller than that predicted by the deterministic approach. It implies that in the face of uncertainty, the

[27] The results for deterministic approach are not the same in all the scenarios because revised forecasts have been used to calculate values in Table 6.1. If linear forecasts were used, the AUC results will be the same for all the demand scenarios.

management is better off building smaller plants and increment capacity on a need-only basis. By AUC metric, the cost of overcapacity is higher than undercapacity (Figure 6.2).

- In low growth scenario, for any choice of capacity (not necessarily the optimal plant size), AUC values in probabilistic case are higher than those predicted from deterministic model because of lower capacity utilization (or build up of excess capacity). On the contrary, in high growth scenario, facilities are operated at higher utilization capacity, which decreases their AUC. As expected, both the models give comparable results when demand is similar to forecasts. Notably there is a greater difference in AUC values when demand does not pick up as forecasted vs. aggressive demand growth. This argument also supports construction of smaller plants because resulting cost savings exceed the additional cost of building more number of plants in case demand grows aggressively.

6.5.2 Capacity Sufficiency

Whether demand growth is sluggish or aggressive compared to forecasts, DCI scores above static approach in terms of *capacity sufficiency*. Capacity sufficiency implies that the system neither allows any backlog of demand nor buildup of excess capacity. In static approach, the optimal plant size and frequency of construction decided years in advance might prove unsuitable in subsequent years if demand does not pickup as expected (as observed in South Africa in 1980's in Section 2.3.2.2). An unexpectedly high demand might force the planners to resort to alternate sources, which may prove more expensive. Table 6.3 contrasts the results of static and dynamic approach for installation of optimal plant sizes determined in Table 6.2. The probabilistic model computes total discounted costs for each simulation (1000 times) of the low, medium and high demand scenario and the average discounted costs are tabulated below .

Table 6.3: Capacity Sufficiency Comparison

	Static	Dynamic		
Demand	**Linear**	**Low**	**Med**	**High**
Optimal Capacity (GWh/year)	300	265	280	340
Number of Plants	10	7	10	11
Total Capacity Installed (GWh)	3,000	1,855	2,800	3,740
Total Discounted Costs (Mkr)	15,773	14,377	15,334	15,792
% Diff from Static Case	-	(9.7)	(2.9)	0.1

Results

In the probabilistic model if the demand in the first decade deviates from forecasted demand by more than a user-defined percentage, the optimal plant size for remaining years is recomputed. As evident from Table 6.3, on a discounted cost basis, the results of DCI in high growth rate case appear worse as compared to static approach. But notice that by the end of 100 years, total demand required a capacity installation of 3,740 units. If the management had proceeded according to static installation strategy, it will result in undercapacity and the cost of resorting to alternate sources of electricity at a short notice might exceed the cost difference between costs computed by the static and dynamic approach. Similarly in case of low growth, if demand worth only 1,855 units materialized, static approach would lead to an overcapacity and block investment in resources which will remain under-utilized.

6.5.3 Value at Risk

The concept of *VaR* as a risk measurement metric was explained in Section 5.5. The probabilistic model gives a distribution of total discounted costs and AUC. *VaR* gives management a handle on expected mean and variance of these variables unlike deterministic strategies in which decisions are made based on mean expected costs only.

Each simulation run constructs a unique demand scenario for a given set of input parameters; the model computes total discounted costs for each run (1000 values). According to the deterministic approach, the optimal plant size was found to be 300 GWh/year. Using the same plant size, four probabilistic demand scenarios were examined and total discounted costs for 1000 simulations of each scenario were recorded (See Table 6.4 for input values used to simulate each demand scenario). The results of 1000 simulations for these 4 demand scenarios are plotted in the form of probability distribution curves in Figure 6.11.

1. Low q_u-q_d range with simulated growth higher than forecasted growth
2. Low q_u-q_d range with simulated growth lower than forecasted growth
3. Low q_u-q_d range with simulated growth similar to forecasted growth
4. High q_u-q_d range with simulated growth similar to forecasted growth

Table 6.4: Input Values for Different Demand Scenarios

	Inputs (GWh/year/year)					Outputs (Bkr)	
Demand Scenarios	q	q_u	q_d	p_u	p_d	Exp Mean	$VaR_{80\%}$
Low Range Low Growth	30	50	10	0.3	0.7	14.7	14.8
Low Range, Medium Growth	30	50	10	0.5	0.5	15.4	15.6
Low Range High Growth	30	50	10	0.7	0.3	15.8	16.1
High Range, Medium Growth	30	60	0	0.5	0.5	15.6	15.8

Results

Deterministic Approach: All the decisions would be based on the total discounted costs of the optimal plant size of 300 GWh/year for a constant demand growth rate of q = 30GWh/year/year: Mkr 15,773.

Probabilistic Approach: Gives a distribution of total discounted costs for each demand scenario. The probability distributions and cumulative probability distributions of total discounted costs for all the 4 cases are plotted in Figure 6.11 and 6.12 respectively;

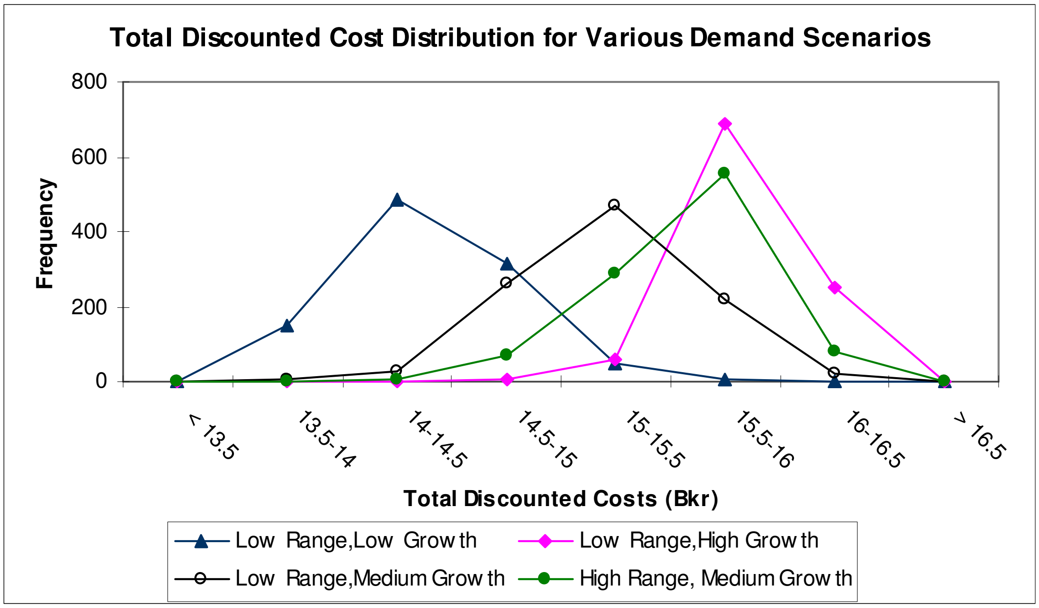


Figure 6.11: Total Discounted Cost Distribution for Various Demand Scenarios

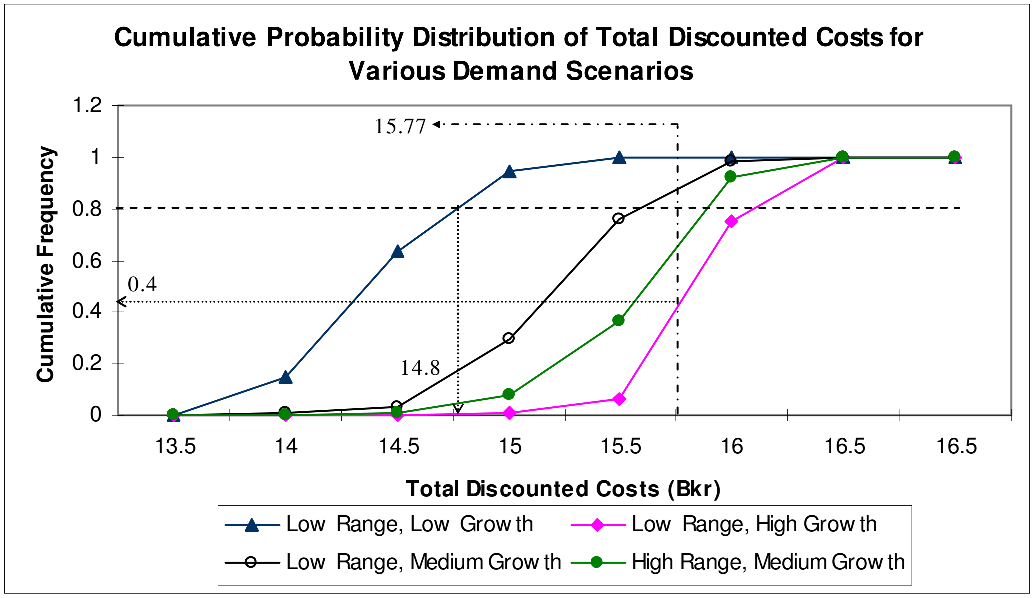


Figure 6.12: Cumulative Probability Distribution of Total Discounted Costs for Various Demand Scenarios

Expected mean of total discounted costs and $VaR_{80\%}$ values are tabulated above ($VaR_{80\%}$ values shown in Figure 6.12 also). The expected mean costs are lower than those computed by the deterministic approach in all cases except when the demand grows rapidly. Even in that case, it can be deduced from Figure 6.14 that the costs exceed the deterministic approach expected costs with approximately 20% probability only ($VaR_{80\%}$ = Bkr 15.8).

This information is essential for planners because they can assess the range of costs and choose a cost distribution aligned with their risk-tolerance. For the same plant size, cost distributions are driven by demand as it dictates the frequency of capacity increment. Clearly expected costs are higher if demand grows aggressively.

This analysis stresses the difference between expected mean costs as calculated by the deterministic approach and different expected mean costs by probabilistic approach. Depending on whether the management is sensitive to maximizing upside potential or minimizing downside risk, *VaR* is an important metric for decision-making. It makes the management cognizant of the distribution of consequences and allows them to make a choice such that both the expected mean and extreme consequences are palatable to their risk appetite.

6.6 Real Options Analysis

This conclusive part of the study distills the essence of all the analysis presented hitherto and demystifies the applicability of ROA (See Section 5.1) in the context of hydropower capacity planning. This section investigates the effectiveness of DCI over the static approach by empowering the management with two different *options*. These *options* can also be thought of as provisions for flexibility in capacity planning. As described in Chapter 1, the 2 *options* are:

1. Option to vary plant size or timing of construction.

2. Option to defer investment in hydropower plants by relying on an alternative source of electricity with an opposite cost profile: low initial investment and high operational costs.

6.6.1 Option to Vary Plant Size or Timing of Construction

Section 6.5 shows that the flexibility to vary size and timing of construction (or DCI) leads to more favorable results (measured by three metrics defined in that section). The reasons why this capacity planning approach resembles an *option*:

1. The management is endowed with decision-making flexibility as the project progresses and uncertainty is resolved.
2. Exercising the option amounts to a variation in the size or timing of construction from that proposed by the deterministic planning strategy. The management is not obliged to choose the size and frequency of construction as suggested by the probabilistic model.
3. The decision depends on the movement of the underlier (AUC or DCF), which are in turn contingent upon the demand uncertainty. A path dependent demand distribution lattice governs AUC and DCF distribution.

The success of ROA is based on the premise that the management is rational and empowered to make decisions as the project progresses based, instead of being forced to advance commitments. Section 6.5.1 and 6.5.2 prove that according to least AUC or discounted cost metrics, dynamic approach recommends a smaller optimal size compared to static approach for variety of demand scenarios. Contingent on demand evolution, by incorporating the flexibility to build smaller plants, management might save costs by as much as 10% as shown in Section 6.5.2 (Low growth case).

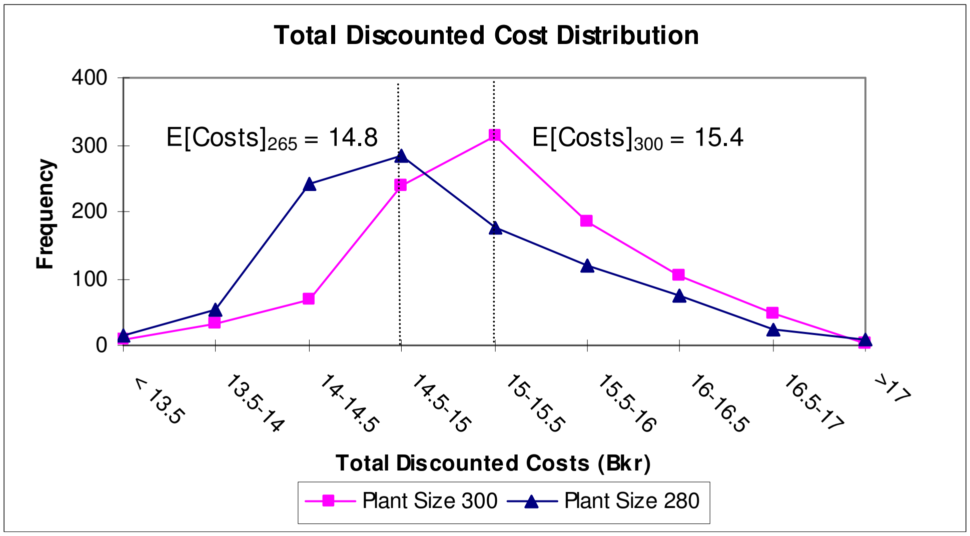


Figure 6.13: Total Discounted Cost Distribution for Option to Construct Smaller Size vs. Forecasted Size

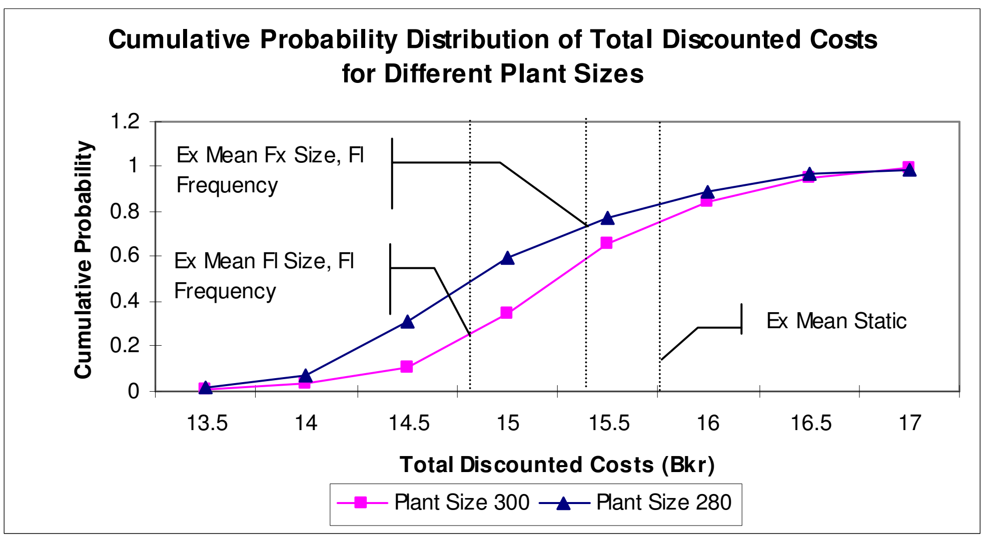


Figure 6.14: Cumulative Probability Distribution of Expected Costs for Option to Construct Smaller Size vs. Forecasted Size

The specific quantitative results of this case are not enough to prove the value of incorporating flexibility but qualitative results obtained by cost distributions plotted in Figure 6.13 and 6.14 corroborate this result by comparing the 2 alternatives: build plants of size 300 GWh/year at a flexible interval; build plants of size 280 GWh/year/year at flexible intervals. By static approach, for *q*=30GWh/year/year, plant of 300GWh should be built in every 10 years, resulting in DCF of Mkr 15,773. Just the flexibility to vary timing of construction brings down the expected costs to Mkr 15,444 and added flexibility to vary plant size to 280 GWh/year/year brings it down further to Mkr 15,334. There is a tradeoff: at the high end of the cost spectrum, the costs in lower size and flexible frequency exceed those in the fixed size and variable frequency case. This study concludes that if planners are cognizant of the demand uncertainty, then it is recommended to build smaller plants at flexible intervals than the size proposed by the static approach.

6.6.2 Option to Defer Hydropower Plant Construction

It is proven that there are benefits to the flexibility of waiting and observing demand before constructing hydropower plants (by relying on an alternate power source in the interim). High initial investment, low operational costs and zero salvage value characterize the cost profile of hydropower plants. An alternate power source with lower initial investment, higher operational costs and non-zero salvage value is chosen to evaluate this option. Oil-fired plants were found to fit the latter cost profile. On a 30 year basis, the cost of hydropower electricity generation per KWh is one of the lowest as compared to other sources of electricity [Fritz 1984]. Oil-fired sourced electricity might prove cheaper on a shorter horizon of 5-10 years but it is economically unviable over an extended period of time against the alternative to build hydropower facilities. Once it is decided that the management wishes to construct hydropower plants, they have 2 investment alternatives:

1. No Option: Invest in hydropower plants today.
   a. Static approach
   b. Dynamic approach with size same as that proposed by static approach but flexible frequency of capacity increment
   c. Dynamic approach with newly determined flexible size and frequency
2. Option: Observe demand for a period of at most 5 years by operating oil-fired plants before investing in hydropower plants with the flexibility to switch from oil-fired plants to hydropower plants at any time during these 5 years. The oil-fired plants can be sold to recover salvage value.

Alternative 1

The results of alternative 1 for a simulated demand similar to linear forecasts of 30GWh/year/year are the same as those expressed in Section 6.5.

Alternative 2

The assumptions for cost profile of the oil-fired plants are as follows:

Capacity: 200 GWh/year

Installation Costs: The cost of installing an oil-fired plant is assumed to be one-fifth that of a hydropower plant. According to Equation 6.1, a hydropower plant of 200 GWh/year costs Mkr 4,931; for input parameters: a=79.815; b=0.778 Mkr, α=0.049). At most one oil-fired plant of capacity 200 GWh/year costing Mkr 1000 will be installed.

Operation Costs: Directly proportional to the demand. It is assumed that on a present value basis, the cost of installing and operating oil-fired plant for more than five years in the high demand case will exceed the cost of installing a hydropower plant. Operation costs in Mkr are thus assumed to be 10 times simulated demand.

Salvage value: The life of an oil-fired plant is assumed to be 10 years, so the salvage value will be zero after 10 years of operation. Assume that on a present value basis, the salvage value decreases non-linearly from Mkr 800 to 500 from one year of operation to five years of operation.

Model

Simulated demand for low, medium, high growth scenarios is for same input parameters as described in Section 6.3.1.1 with average expected growth rate = 30 GWh/year/year. The model computes and compares results for three design approaches:

DCI with Option to Defer: An oil-fired plant is installed in year zero and DCF is calculated for switching to hydropower in year 1, 2, 3, 4 or 5. The hydropower plants of optimal size found in Section 6.5.2 are installed at flexible intervals thereafter. The year in which switching leads to the least DCF is recorded for each demand scenario.

DCI with No Option to Defer (Variable Size and Frequency): These results are the same as those in Section 6.5.2 when optimal sized hydropower plants are installed at a flexible interval.

DCI with No Option to Defer (Fixed Size and Variable Frequency): These results are recapitulated from Table 6.4 when the optimal size found according to static approach (300 GWh/year) is installed at flexible intervals such that DCF is minimized.

Static Installation with No Option to Defer: This result is the same as that computed for linear demand in Section 6.5.2 when a plant size of 300 GWh/year based on expected demand growth of 30 GWh/year/year is installed every 10 years regardless of the demand uncertainty.

Results

Results obtained from the model to defer are condensed in Table 6.5 (expected means of DCF distribution). It is beneficial to wait and observe demand both in the low and medium demand growth scenarios. The benefits are 2 pronged:

1. When interest rates are steep, the total discounted costs of installing and operating oil-fired plants may be less than the gains realized due to time value of money by deferring huge investments in hydropower facilities.
2. By observing demand for a few years, management has the option of reassessing optimal plant size. It was shown in section 6.5.2 that in case the simulated demand deviates from forecasted demand consistently by more than a user-specified percentage, the model recalculates optimal plant size for the remaining years. In high and low growth scenario, the optimal plant size may be up or downscaled. Thus management stands to gain from the perspective of both cost efficiency and capacity sufficiency.

The gains are highest in case of depressed demand growth. Major improvement in DCF is owed to readjustment of optimal capacity size after observing demand during the years oil-fired plants are operated, augmented by gains from delayed investment in hydropower plants due to time value of money. In case the demand grows rapidly, it is cheaper to build hydropower plants right from the beginning because cost of operating oil-fired plants bludgeons with increasing demand.

Table 6.5: Analysis of Option to Defer

(Costs in Mkr) (Capacity in GWh/year)	Simulated Demand Growth Low	Med	High
DCI with Option to Defer (Variable Size and Frequency)			
Oil Fired Plant			
Capacity	200	200	200
No. of plants	1	1	1
Years Before Switching to Hydropower	5	4	4
DCF of installation and operation costs	4,008	4,472	5,761
DCF Salvage Value	500	650	650
Net Cost of Operating Oil-Fired Plants	3,508	3,822	5,111
Hydropower Plants			
Capacity	265	280	340
No. of plants installed after switching	6	9	10
DCF of hydropower plant construction	9,186	11,054	11,960
Total Cost of Oil-Fired + Hydropower Plants	12,694	14,876	17,071
DCI with No Option to Defer (Variable Size and Frequency			
Capacity	265	280	340
No. of hydropower plants installed	7	10	11
DCF of hydropower plant construction	14,377	15,334	15,792
% Cost Savings in Option to Defer	13	3	(7)
DCI with No Option to Defer (Fixed Size/ Variable Frequency)			
Capacity	300	300	300
No. of hydropower plants installed	7	10	13
DCF of hydropower plant construction	14,709	15,444	16,149
% Cost Savings in Option to Defer	16	4	(5)
Static Installation with No Option to Defer			
Capacity	300	300	300
No. of hydropower plants installed	10	10	10
DCF of hydropower plant construction	15,773	15,773	15,773
% Cost Savings in Option to Defer	24	6	(8)

There is another way of assessing the benefits of the option to defer apart from the expected mean basis (Table 6.5). It allows the management to modify the cost distribution. The cost distribution curves in Figure 6.15 and 6.16 correspond to 2 cases: Option to Defer and No Option build plants of size 300GWh at flexible time interval as required; build plants of size 280 GWh/year/year at flexible intervals with the option to defer construction (average demand growth). Not only the mean expected cost is lower when management has the option to defer (vertical lines in Figure 6.15), observe the change in cost distributions.

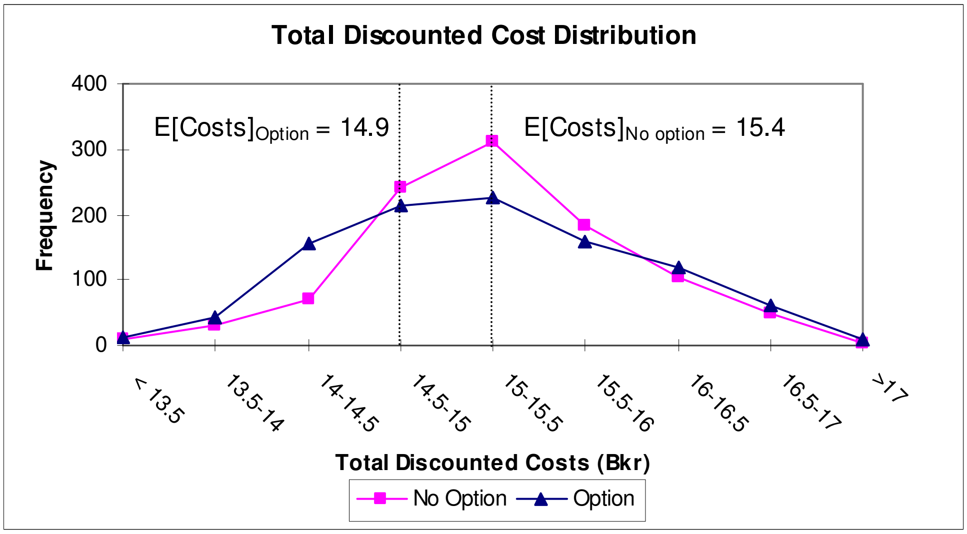


Figure 6.15: Total Discounted Cost Distribution for Option to Defer and No Option

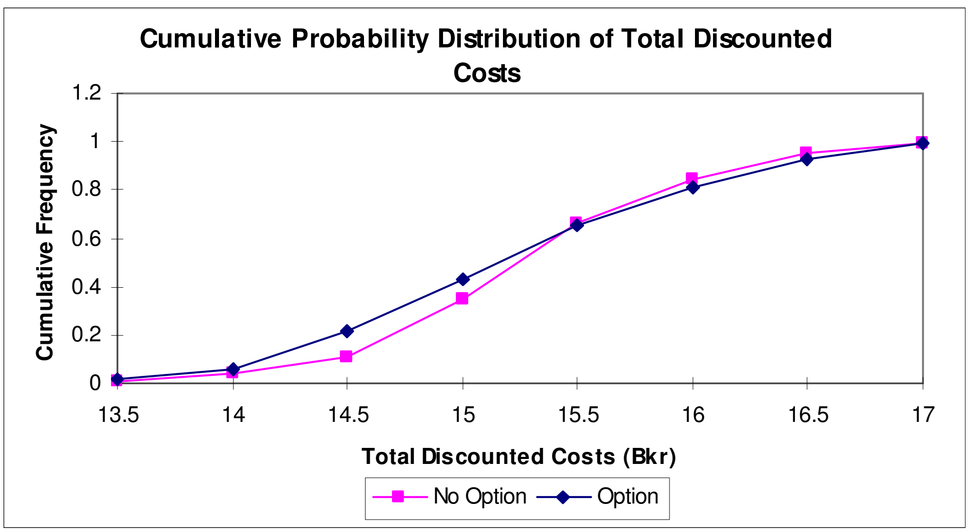


Figure 6.16: Cumulative Probability Distribution of Total Discounted Costs for

When management has the option to defer, the frequency of costs at the low and high end of the spectrum outstrips that in the no-option case. $VaR_{60\%}$ is lower whereas $VaR_{80\%}$ is higher with the option to defer. This suggests a tradeoff between minimum and maximum expected costs, but in an average situation, management benefits with the option to wait and observe demand. Again as concluded in Section 6.6.1, the choice of alternative depends on the management's goals, demand expectations and risk-preferences.

7 Conclusions

This study has corroborated some commonly known facts and gleaned some valuable insights. The important conclusions are recapitulated and some Figures are repeated:

- ***The real world is ridden with substantial uncertainty***: In the context of capacity planning, uncertainty manifests as system-wide risks (demand uncertainty) as well as project-specific risks (construction delays). Chapter 3 proved that meticulously drawn forecasts at best suffice as a pointer towards what the future holds.

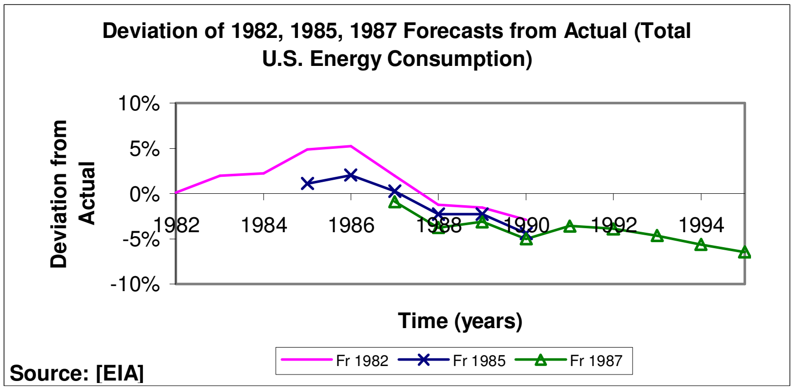


Figure 3.5: Deviation of Long Term Forecasts from Actual (Total U.S. Energy Consumption)

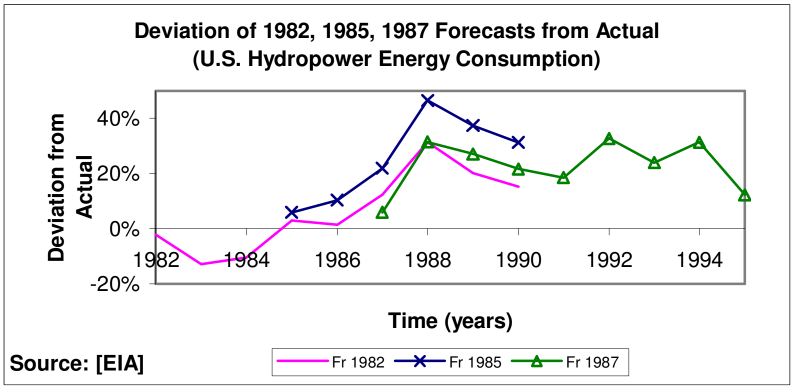


Figure 3.8: Deviation of Long Term Forecasts from Actual (U.S. Hydropower Energy Consumption)

The actual realization of any parameter can not be predicted accurately in spite of sensitivity and scenario analyses which accompany forecasts (See Figure 3.5 and 3.8). The quality of decisions based on forecasts is only as good as the quality of forecasts. The conclusion is that forecasts provide an unreliable premise for decision-making if they are used to judge expected value of input parameters.

- ***Optimal capacity size is sensitive to uncertainty***: The capacity planning models in Chapter 4 and 6 propose an optimal capacity size judged by Discounted Cash Flow (DCF) or Actual Utilization Cost (AUC) metrics by assuming a constant rate of demand growth, economies of scale parameter and interest rates: all derived from forecasts.

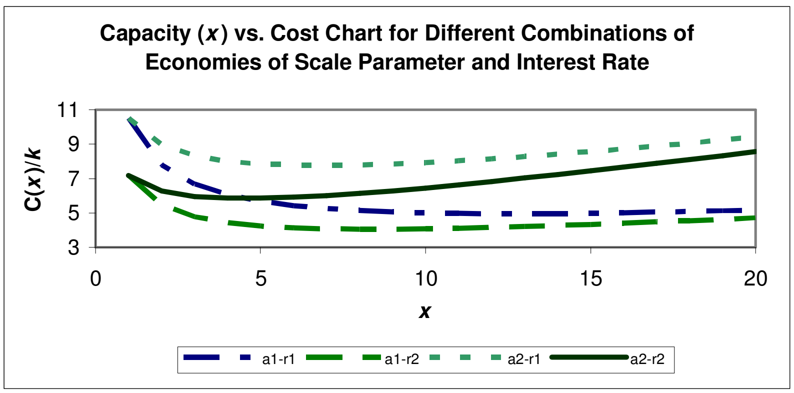


Figure 4.4: Capacity vs. Cost Chart

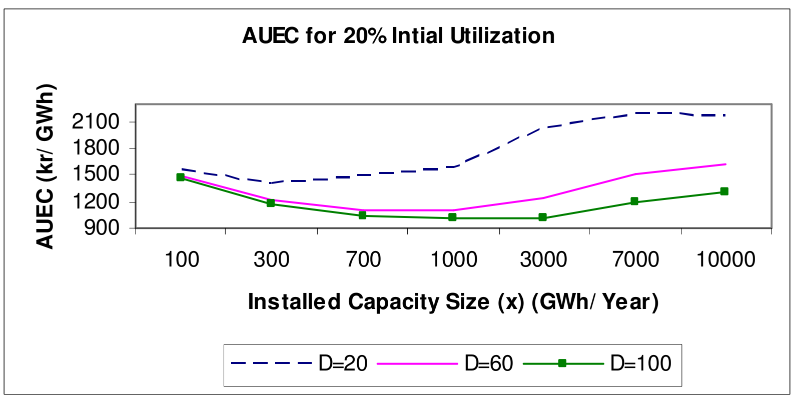


Figure 6.5a: AUEC at 20% Initial Utilization for Various Demand Growth Rates

The consequences of uncertainty in these parameters are not addressed suitably. Figure 4.4 and 6.5a show the impact of variation in input parameters on the optimal size.

- ***Optimal size should be dictated by both economies of scale and percentage of capacity utilization***: The same figures above also indicate a difference of approach towards choosing the optimal size based on DCF and AUC metric. The DCF methodology explained in Chapter 4 is more sensitive to undercapacity (steeper curve for plant sizes less than the optimal size). AUC methodology is more sensitive to overcapacity (steeper curve for plant size greater than the optimal size). DCF methodology is driven by economies of scale benefits only; it ignores the cost of operating facilities at a sub-optimal level in case sufficient demand does not materialize. AUC methodology balances installation costs and capacity utilization to minimize overall cost of electricity produced per unit cost of installation. Given the uncertainty of demand and plant-utilization, AUC approach should be favored over DCF.
- ***In the face of uncertainty, flexible ROA-based capacity planning approach is more effective than conventional approaches***: It is beneficial to embed flexibility in capacity planning, permitting the management to react optimally as clouds of uncertainty clear up with a passage of time. Instead of building plants of a pre-determined size at fixed frequency based on expected demand (static capacity installation), better strategy is to consider the distribution of demand and observe the contingent outcomes. Then based on the distribution of outcomes, choose a plant size which minimizes costs in all the manifestations of demand and increment capacity on

a need-only basis (dynamic capacity installation or DCI). See Table 6.3 for optimal plant size recommended by different approaches for multiple demand scenarios. This is the key to managing the risk due to demand uncertainty.

Table 6.3: Capacity Sufficiency Comparison

	Static	Dynamic		
Demand	**Linear**	**Low**	**Med**	**High**
Optimal Capacity (GWh/year)	300	265	280	340
Number of Plants	10	7	10	11
Total Capacity Installed (GWh)	3,000	1,855	2,800	3,740
Total Discounted Costs (Mkr)	15,773	14,377	15,334	15,792
% Diff from Static Case	-	(9.7)	(2.9)	0.1

Figure 6.14 contrasts the results for average demand in static approach (build 300 GWh/year in every 10 years) and 2 types of DCI: fixed plant size and flexible frequency (build 300 GWh/year when required), flexible plant size and frequency (build 280 GWh/year when required). Both the DCI distributions emphasize that flexible strategy scores over static on an expected-cost basis but depending on the demand manifestation, there can be chances that costs exceed those computed in the static case.

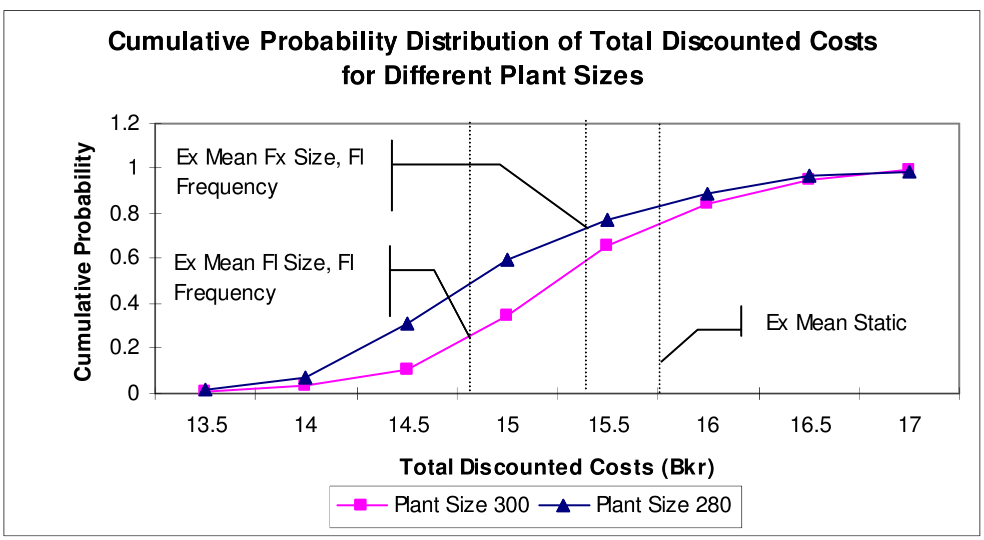


Figure 6.14: Cumulative Probability Distribution of Expected Costs for Option to Construct Smaller Size vs. Forecasted Size

- ***Options empower the management to manage the risk of uncertainty by reducing expected costs and controlling the cost distribution***: The option to defer construction of hydropower plants to observe demand for a maximum of five years by operating oil-fired plants in the interim also helps the management to manage the risk of demand uncertainty. Notice the change in cost distribution when you install a plant of 300 GWh/year as required vs. installing plants of size 280 GWh/year as required with the option to defer construction. Figure 6.15 proves that the strategy with embedded option performs better on an expected cost basis; costs are lower on the left end of the spectrum and higher on the right end of the spectrum. Therefore the management has potentially bought some down-side protection by acquiring greater up-side risk.

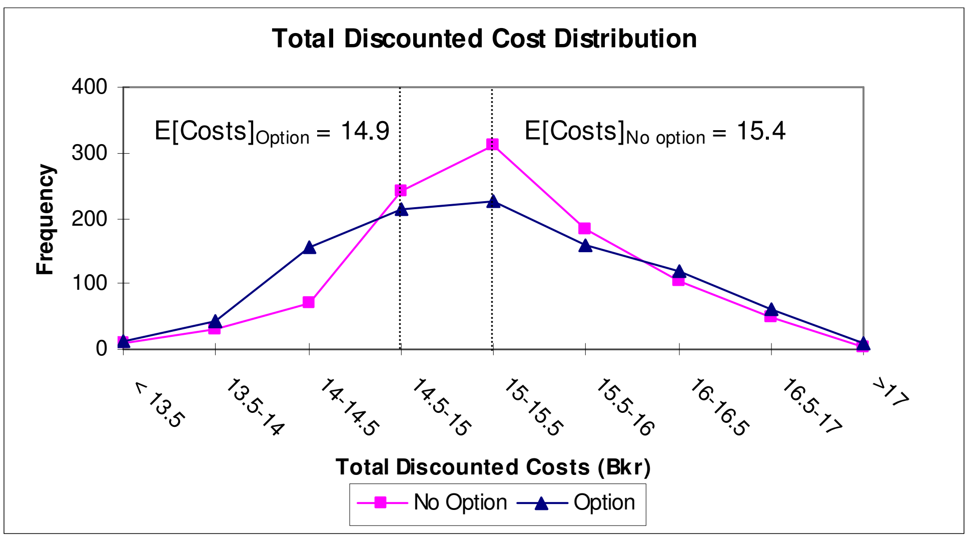


Figure 6.15: Total Discounted Cost Distribution for Option to Defer and No Option

The study does not conclude a favorable strategy in any of the situations examined because it is completely conditional upon the long-term objectives and management's risk appetite. However the study does present a fresh perspective on capacity planning and suggests how to manage the risk due to uncertainty.

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APPENDICES

APPENDIX A: MONTE CARLO SIMULATIONS IN MICROSOFT EXCEL

Monte Carlo Simulations (MCS) can be generated in Microsoft Excel with the help of 2 provisions: function RAND, tool DATA TABLE.

RAND: Returns an evenly distributed random number greater than or equal to 0 and less than 1. A new random number is returned every time the worksheet is calculated.

DATA TABLE: Data tables are part of a suite of commands sometimes called what-if analysis tools. A data table is a range of cells that shows how changing certain value in your formulas affects the results of the formulas. Data tables provide a shortcut for calculating multiple versions in one operation and a way to view and compare the results of all of the different variations together on your worksheet.

Practical application to an example of coin toss simplifies the explanation. Suppose you wish to compute the frequency heads or tails for 100 tosses of an unbiased coin. One could either toss the coin actually a 100 times or conveniently setup MCS in Microsoft Excel.

Steps:

1. Input formula in cell C3: =if((RAND()<0.5,"Head","Tail")
2. Enter numbers from 1 to 100 in range B6:B105
3. Enter formula in cell C5: =C3
4. Select range B5:C105
5. Data>Table: Opens an input box. Choose any random cell in “column input cell”
6. Range C6:C105 contains the results of this simulation (Head or Tail).
7. Proceed with this distribution of results as desired

APPENDIX B: PROBABILISTIC MODEL FOR TOTAL DISCOUNTED COSTS

B1: INPUT SHEET

PROBABILISTIC MODEL FOR TOTAL DISCOUNTED COSTS **(Press Shift+F9 Key after inputting the parameters to run the model)**

PARAMETER DESCRIPTION	NOTATION	VALUE	UNITS	Comments
Initial demand	Do	0	units/year	
forecasted increase in demand	q	30	(units/year)/year	
Upper Bound for Demand Growth	Du	40		Maximum permissible demand growth rate
Probability that Demand Growth is Upper Bound	Pu	20%		Probability q<actual demand growth<Du
Lower Bound for Demand Growth	Dl	0		Mimimum permissible demand growth rate
Probability that Demand Growth is Lower Bound	Pl	80%		Probability Dl<actual demand growth<q
Annual discount rate	r	5.0%		
EOS parameter (b)	b	0.7783		for EOS: 0<b<1
Constant of proportionality (a)	a	79.815		Expressed in Icelandic currency
Initial Capacity (x)	xo	265		Intial capacity & subsequent capacity increment size
Intial Utilization Percentage	y	0%		Fixed demand posed by heavy industry as a % of intial installed capacity
Re-estimate Demand Forecast if mismatch greater than		5%		If deviation between actual and forecasted demand exceeds this percentage in the last 3 years of every forecast period then forecast for the next period are adjusted

DERIVED PARAMETERS			
Alpha	0.0488	ln(1+r/100)	For calculating continuous time discounted costs

B2: SNAPSHOT OF MODEL SHEET
(Only years 0-10 shown)

Input Parameters (As per Sheet: Input)		
Intial Capacity	265	
Base Case Demand Growth	30	
Demand Growth		Probability
Upper Bound	40	20%
Lower Bound	0	80%
Re-estimate Threshold	5%	
a	79.815	
b	0.778	
Alpha	0.049	

MODEL YEAR	0	1	2	3	4	5	6	7	8	9	10
Random Function	0.205395	0.395232	0.783263	0.638065	0.652456	0.98248	0.147791	0.668138	0.997654	0.17057	0.37668
Deterministic Capacity	265	265	265	265	265	265	265	265	265	530	530
Dynamic Capacity (xi)	265	265	265	265	265	265	265	265	265	265	265
Initial Demand (Do)	0										
Forecasted Demand Growth (q)	30										
Simulated Demand Growth	10.37	10.95	1.74	27.31	11.01	32.98	15.45	7.39	33.67	25.10	26.23
Forecasted Demand	0	30	60	90	120	150	180	210	240	270	300
Simulated Demand	0.00	10.37	21.32	23.06	50.37	61.38	94.36	109.81	117.20	150.86	175.96
Devn of Forcst from Slmltd	0.00	-19.63	-38.68	-66.94	-69.63	-88.62	-85.64	-100.19	-122.80	-119.14	-124.04
Extra Demand (yi)	0	0	0	0	0	0	0	0	0	0	0
Total Demand (Forecasted)	0	30	60	90	120	150	180	210	240	270	300
Total Demand (Simulated)	0.00	10.37	21.32	23.06	50.37	61.38	94.36	109.81	117.20	150.86	175.96
New Const Rqd in next period?	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Demand Met?	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
Cost of Installation (Simulated)	6138.988	0	0	0	0	0	0	0	0	0	0
Discounted Cost (Simulated)	6138.988	0	0	0	0	0	0	0	0	0	0
NPV (Simulated)	12866.51										
Cost of Installation Forecasted)	6138.988	0	0	0	0	0	0	0	0	6138.988	0
Discounted Cost (Forecasted)	6138.988	0	0	0	0	0	0	0	0	3957.246	0
Total Discounted Cost (Forecasted)	13816.11										

B3: FORMULAS IN MODEL SHEET
(Only years 0 and 1 shown)

Input Parameters (As per Sheet: Input)		
Intial Capacity	=+Inputs!D15	
Base Case Demand Growth	=+Inputs!D7	
Demand Growth		Probability
Upper Bound	=+Inputs!D8	=+Inputs!D9
Lower Bound	=+Inputs!D10	=+Inputs!D11
Re-estimate Threshold	=+Inputs!D17	
a	=+Inputs!D14	
b	=+Inputs!D13	
Alpha	=+Inputs!C21	
Random Function	=RAND()	=RAND()
MODEL		
YEAR	0	=J17+1
Deterministic Capacity	=+J4	=IF(K27>J18,J18+$J$18,J18)
Dynamic Capacity (xi)	=+J4	=IF(J29,J19+$J$4,J19)
Initial Demand (Do)	=+Inputs!D6	
Forecasted Demand Growth (q)	=+J5	
Simulated Demand Growth	=IF(J14<$K$8,$J$8+RAND()*($J$5-$J$8),$J$7-RAND()*($J$7-$J$5))	=IF(K14<$K$8,$J$8+RAND()*($J$5-$J$8),$J$7-RAND()*($J$7-$J$5))
Forecasted Demand	=J20	=J23+$J$21
Simulated Demand	=J20	=J24+J22
Devn of Forcst from Simltd	=J24-J23	=K24-K23
Extra Demand (yi)	=+Inputs!D16*$J$4	=+J26
Total Demand (Forecasted)	=J23+J26	=K23+K26
Total Demand (Simulated)	=J26+J24	=K26+K24
New Const Rqd in next period?	=IF(J19-J28<$J$7,TRUE, FALSE)	=IF(K19-K28<$J$7,TRUE, FALSE)
Demand Met?	=IF(J19-J28>0,TRUE,FALSE)	=IF(K19-K28>0,TRUE,FALSE)
Cost of Installation (Simulated)	=IF(J19=I19,0,$J$10*$J$19^$J$11)	=IF(K19=J19,0,$J$10*$J$19^$J$11)
Discounted Cost (Simulated)	=J31*EXP(-$J$12*J17)	=K31*EXP(-$J$12*K17)
NPV (Simulated)	=SUM(J32:DF32)	
Cost of Installation Forecasted)	=IF(J18=I18,0,$J$10*$J$18^$J$11)	=IF(K18=J18,0,$J$10*$J$18^$J$11)
Discounted Cost (Forecasted)	=J34*EXP(-$J$12*J17)	=K34*EXP(-$J$12*K17)
Total Discounted Cost (Forecasted)	=SUM(J35:DF35)	