FINANCIAL AND REGULATORY CONSIDERATIONS IN CAPACITY

EXPANSION PLANNING FOR THE ELECTRIC UTILITY INDUSTRY

by

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PREFACE

Electric utility capacity planning models are used by a wide range of users including utility management, regulators and national policy analysts. A significant amount of sophistication has been added to these models in the past decade. Present day models are much more sophisticated than earlier models in terms of the financial uncertainty and time dynamic settings of the electric utilities.

The present research work has been supported by the Department of Energy, thus, it has a characteristic national policy analysis slant. The national policy analysis context has made some issues more important and rendered some others insignificant. For example, reliability considerations are simplified considerably at the national and regional levels compared to a particular utility. For an aggregated set of utilities at the national or regional levels, an average reliability of generation plant can typically be used to derate the nameplate capacity to the effective capacity.

The following dissertation has been divided into four sections. The first section consists of an overview of historical development of electric utilities and their current setting in U.S. economy and a literature review to identify the most important financial and regulatory issues for electric utilities. Some of the proposed financial models for electric utilities are also reviewed and assessed in terms of their strengths and weaknesses.

In the second section, some current capacity expansion planning models are reviewed and some extensions for these models are presented.

In the third section, the effect of regulation on electric utility capacity planning is analyzed. In the first chapter of this section, a basic share price maximization model, with regulation explicitly modeled, is presented for an all equity firm. In the next chapter, some of the assumptions of the model are relaxed.

In the final section, a methodology for incorporating a capital supply curve into a capacity planning model is presented. In the first chapter of this section a mathematical program for a single period model which incorporates the capital supply curve is presented and the characteristics of its solution are analyzed. In the second chapter, a methodology for estimating the capital supply curves for electric utilities is given.

CHAPTER 1

U.S. ELECTRIC UTILITY INDUSTRY--AN OVERVIEW

1.1 Introduction

In the twentieth century electricity has obtained paramount importance in our individual life styles and has led to major improvement in the standard of living in almost all developed countries. As shown in Figure 1.1, the United States leads all the other countries in the production of electricity. Electricity has become so important largely because of its versatility. It is usable energy that can be produced from a variety of sources--coal, oil, gas, hydro, solar, geothermal, etc. It can be used for a wide range of purposes in residential, commercial and industrial establishments. However, this versatility is achieved by sacrificing efficiency for it takes about 3 Btu of energy input to yield 1 Btu of electricity as output. Another reason for the wide use of electricity is the fact that its use is essentially pollution free for the end user. However, generation of electricity concentrates pollutants in a localized and highly visible source.

The electric utility industry is an essential and a major segment of the U.S. economy. According to 1980 statistics [15], the electric utility industry has $262 billion in assets and produces $92 billion in revenues each year. Currently, the electric utility

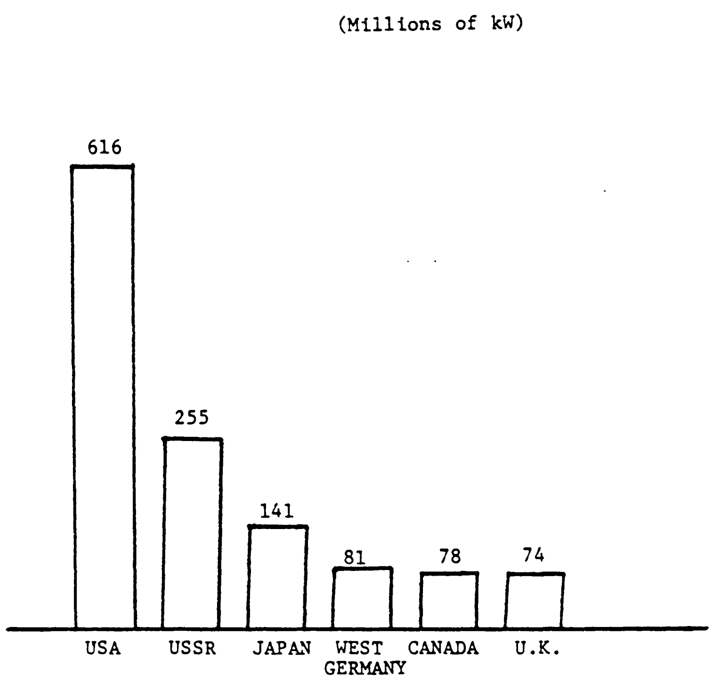

Figure 1.1. World Generating Capacity

Source: Edison Electric Statistical Yearbook, 1980

industry consumes 70% of U.S. coal consumption and supplies 27% of the total energy ultimately consumed. The total coal consumption by the electric utilities during 1979 amounted to 527 million short tons. In contrast, total oil consumption was 523 million barrels and a total of 3491 trillion cubic feet of gas was used by the electric utilities. The percentages of net generation by different fuel types is shown in Figure 1.2.

1.2 Historical Evolution of Electric Utility Industry

The early part of the twentieth century was characterized by inefficient technology for the electric utility industry. The generation of power was not very efficient and boiler efficiencies were very low.

In addition, regulation of the electric utilities was largely ineffective. "Fair value" valuation, in which the fair market value of the property being used by the utility for the convenience of public is assessed, was the predominant view of the regulators. This emphasis on "fair value" stemmed from the case of Smyth vs. Ames [46] and transformed intensely practical questions into high level abstractions about the nature of "value." Holding companies holding controlling interest in several utilities dominated the electricity industry. These systems of holding companies were able to evade the state control and were unregulated at the federal level.

For the period from the beginning 1920's to the great depression, the electric utility rates were volatile. Every-

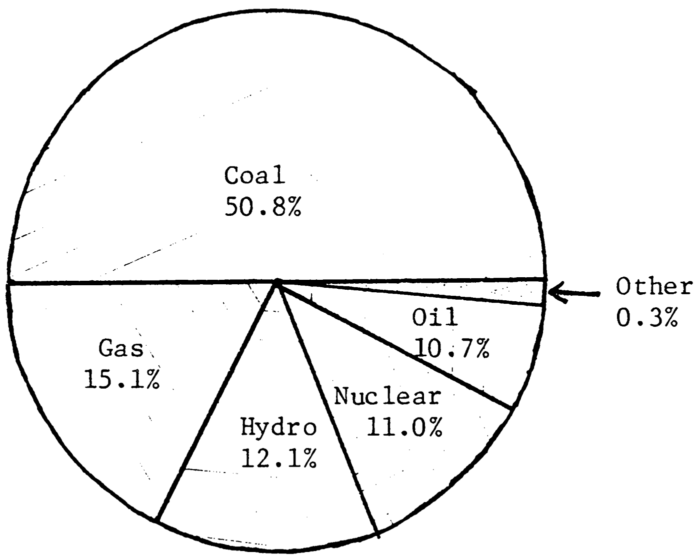

Figure 1.2. Percent Net Generation by Fuel Type
Source: Electric Power Monthly, May 1981

thing else was becoming cheaper in an age of severe deflation. Investors suffered in the holding companies' securities. Both investors and consumers wanted efficient regulation. The needs of investors and consumers for efficient regulation culminated in the Public Utility Act of 1935. During the same period the federal government enacted the Federal Power Act and the Public Utility Holding Company Act. The passage of these acts led to the long federal presence in the regulatory scene. Utilities became liberated from the holding companies, the rates came down and the regulation of electric utilities worked well, both for investors and consumers.

The period from the end of World War II to the end of the 1960's can be termed as the "golden age" for the electric utility industry. The economics of the electricity business was such that companies could build new generating plants, extend their transmission and distribution networks, improve the reliability of service, meet the growing need of customers for electricity, and still be in a position to charge a lower average price per kWh. In this period the technological progress in electric power generation and transmission was astounding. Manufacturers built larger generating units which were more efficient.

The total electricity consumption grew at a compound annual rate of 7.8% between 1945 and 1970. Also, peak loads grew at 8.1%. Due to use of bigger and more efficient plants, the electric utilities were able to realize significant gains in operating efficiency.

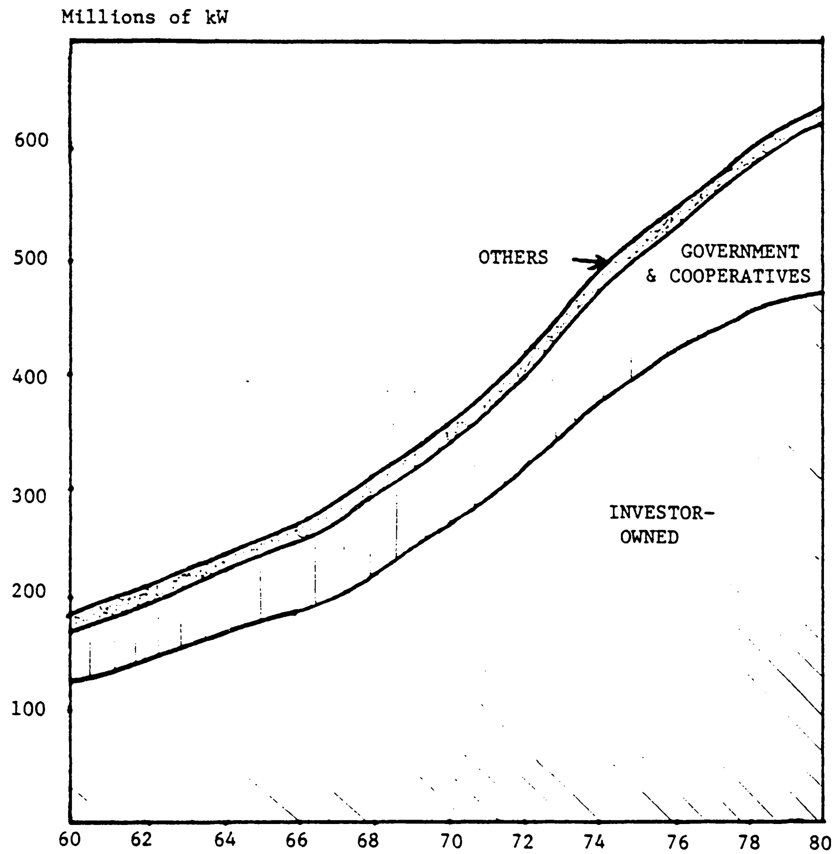

Figure 1.3. Total Installed Generating Capacity

Source: Edison Electric Statistical Yearbook, 1980

The industry had a decreasing unit cost character. Low cost supply of fossil fuels were available. A significant improvement in transmission and distribution technology also took place.

An increasing use of hydroelectric power in this period led to lower operating costs. The hydro generation rose 4.6% annually and the installed hydro capacity grew at 8.7% a year. All these factors contributed to a decline in operating and maintenance (O&M) cost per kWh. (see Table 1.1).

As consumers used more electricity, rates could be lowered in a decreasing unit cost situation and still allow for growing profit and an attractive return on equity. From 1926 to 1969, the average price of electricity charged by investor-owned utilities trended downward (see Figure 1.4).

The firms implemented the so-called "declining block" rates under which the consumer consuming more electricity was charged a lower price per kWh. The motivation behind the "declining block" rate structure was to encourage increasing usage of electricity and to take advantage of the associated economies of scale. The business risk factor was low and new investment in power plants was "safe." Due to these reasons, the profitability and price-earnings ratio of power companies compared favorably with other companies. The period after World War II to the beginning of the 1970's was a period of tranquility for the electric utility regulators. In 1968, there were only three rate increase applications received by the Federal Power Commission. Investors had

Table 1.1

Electricity O & M Expenses per kWh

Year	Annual kWh Generation (in billions	O & M Expenses per ¢/kWh
1950	266.9	.920
1955	420.9	.803
1960	578.6	.778
1965	809.5	.665
1980	1019.3	.658

Source: 1980 Edison Electric Statistical Yearbook

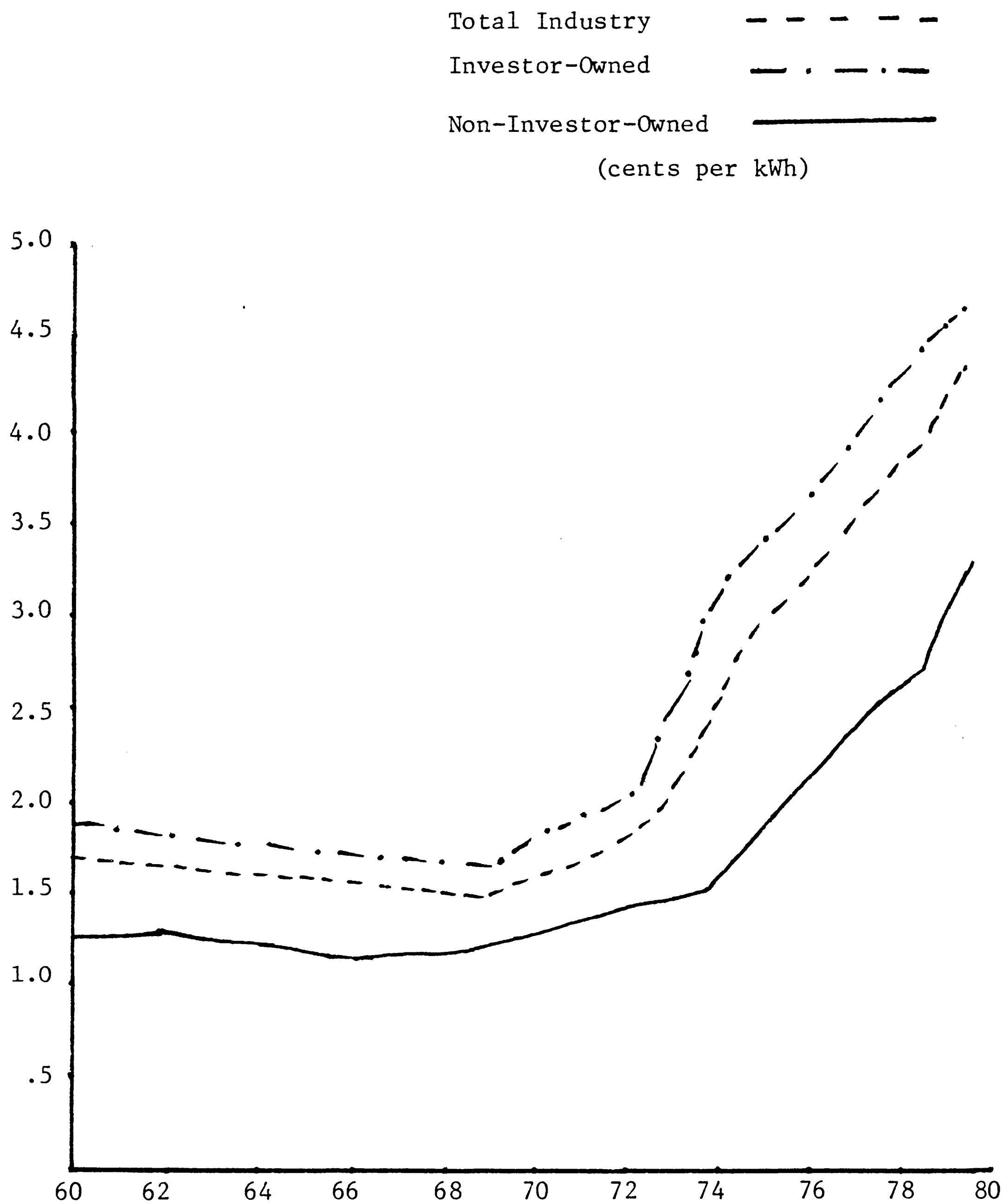

Figure 1.4. Electricity Price Trend

Source: Edison Electric Statistical Yearbook, 1980

a good appetite for utility securities. In real terms electricity became much cheaper than in the past.

The period starting from 1970 can be termed as a period of agony for electricity industry. The character of the falling cost economy of electricity industry changed to that of a rising cost economy. There were many reasons for the reversal in the character of economics of electricity business.

Since the mid-sixties the technological improvements in efficiency of power plants became saturated. The decreasing cost economies of large-scale operations no longer existed. The optimum plant size has remained in 800-1000 megawatt range. Also, the most advantageous hydro sites were all occupied by the beginning of this period. The increasing use of hydro which led to lower operating costs was no longer present. New additions to on-line generating capacity now started bringing up the average kWh cost of supplying electricity.

The plant construction costs increased at a tremendous rate as evidenced in Table 1.2. One factor for the rise in the construction cost has been inflation. With inflation, construction, labor and material costs have increased substantially. In addition to inflation, the increased environmental and safety requirements for new power plants caused the construction costs to soar. The major environmental or safety changes for nuclear reactors required more complex cooling systems to prevent damage to local aquatic life, and systems to assure minimal release of radioactivity. The major environmental

Table 1.2

Construction Cost Index for North Atlantic Region (1949 = 100)

Date	Index
Jan., 1971	217
July, 1971	229
Jan., 1972	241
July, 1972	245
Jan., 1973	249
July, 1973	262
Jan., 1974	276
July, 1974	313
Jan., 1975	341
July, 1975	362
Jan., 1976	367
July, 1976	379
Jan., 1977	385
July, 1977	403
Jan., 1978	409
July, 1978	421
Jan., 1979	441
July, 1979	466
Jan., 1980	487
July, 1980	505
Jan., 1981	532

Source: Edison Electric Institute Statistical Yearbook, 1981 restrictions for coal-fired power plants require scrubbers to desulfurize the flue gas, precipitators to remove fly ash, and additional water cooling requirements.

This added environmental and regulatory burden led to escalation of construction costs both directly and indirectly. These added requirements needed more materials and more manhours which led to higher construction costs. They also resulted in construction lead times jumping from 5 years to 9-10 years. This led to higher accumulated interest during the lead period, resulting in relatively high costs for the plants entering the rate base.

The book value of new plants not only increased because of longer lead times, interest costs also soared in this period. The increase in the interest rates are evident in Table 1.3. Had the interest expenses of electric utilities increased only in proportion to generating capacity, then the 1980 interest charges for the whole U.S. electric utility industry would have been only \$4.2 billion instead of \$10 billion. The difference of \$5.8 billion provides a rough estimate of the impact of inflation on electric utilities interest costs.

Another subtle factor causing the construction costs to increase is the increased delays in licensing and siting. Utilities face numerous difficulties in obtaining the license for a new power plant. Some of the major reasons for the delays in licensing and siting were the laws enacted in the late 1960's and early 1970's,

Table 1.3

Average Yields of Electric Utility Bonds

Year	Weighted Average Yield on Newly Issued Bonds of Electric and Gas Utilities
1960	4.72%
1965	4.61%
1970	8.79%
1975	9.97%
1976	8.92%
1977	8.43%
1978	9.30%
1979	10.85%
1980	13.46%

e.g., the National Environmental Policy Act, the Federal Water Pollution Control Act, and the Clean Air Act Amendments, etc.

The Three Mile Island accident has also caused major delays in the licensing of the new nuclear power plants. The increased delays associated with licensing and siting has further increased the construction lead times leading to further increases in book value of new plants. The combined effect of all these causes has been tremendous. The compound annual growth rate in construction costs in the 1970's has been 9.38%. Table 1.2 shows the construction cost index during the 1970's.

In addition to mushrooming construction costs during the 1970's, fuel costs have also soared, especially oil. The Clean Air Act Amendments of 1970 led to a shift in utility fuel mix. A number of existing coal plants were switched to low sulphur oil in order to meet the ambient air standards. Then, the oil embargos of 1973 and 1979 made coal again the most attractive fuel for power plants. In 1980, for the first time after 1968, more than 50% of the U.S. electricity generation was by coal.

The tremendous increase in fuel costs encouraged large-scale use of fuel adjustment clauses. By using fuel adjustment clauses the utilities can pass the increase in fuel costs to the consumers in terms of higher prices without prior approval of the regulatory body. Thus, the fuel adjustment clauses shield the utilities against the severe inflation in fuel costs. The increasing nature of fuel costs in the last years of the 1970's is depicted in Table 1.4.

Table 1.4

Costs of Different Fuels in Cents/Million BTU

Year	Coal	Oil	Gas
1975	81.4	201.4	75.4
1976	84.8	195.9	103.4
1977	94.7	220.4	130.0
1978	111.6	212.3	143.8
1979	122.4	299.7	175.4
1980	135.2	427.9	212.9

Source: Edison Electric Institute Statistical Yearbook, 1980

A more subtle factor is the change in the nature of electricity demand. The peak demand has been growing faster than the average demand, leading to a reduced economic efficiency. The capital intensiveness of the electric utility industry has further amplified the effect of this swing in demand.

Environmental critics of the electric utility industry have been much more visible in recent years. Aiming to reduce the total installed capacity and supported by the economic principles of marginal cost pricing, environmentalists have advocated the use of "seasonal" and "time-of-day" rates. Faced with an increasing price of electricity, consumer groups advocated the use of "lifeline rates" under which the households using a very small amount of power pay lower prices for power. The rationale behind the use of "lifeline rates" is that a very small amount of power is supposed to be an "essential need" and "lifeline rates" help very poor households to be able to get enough power to meet this need.

The aforementioned forces led to the enactment of the Public Utility Regulatory Policy Act (PURPA) in 1978. The PURPA Act is an effort by the federal government to affect the ways in which the state public utility commissions regulate the retail sales of electric and gas utility companies. The Act expands the authority of Federal Energy Regulatory Commission in certain areas of electricity supply such as inter-connection, co-generation, etc. The Act establishes certain requirements and guidelines for state public utility commissions to follow in establishing retail electricity rates. The Act requires the state commissions to consider the applicability of certain specific rate making standards like "seasonal rates," "declining block rates," etc. The main objectives of the Act are to foster increased conservation and efficiency in the electric utility industry.

The accelerating inflationary forces on the electric utility industry have led to a massive increase in the number of rate relief applications received by the regulatory agencies. In 1968, the former Federal Power Commission received a total of only three applications for rate relief. In contrast, in 1973 this number increased to 56, attaining an all-time high of 191 in 1976. In 1979, the number of such applications was 153, not too much below the all time high. As a consequence, the load on the regulatory agencies has increased substantially. During 1975, utility commissions granted rate increases amounting to more than \$3 billion. Nevertheless, at the end of the year, requests amounting to more than \$4 billion were still awaiting commission action. The regulatory commissions' staff has not increased at any significant rate as compared to the number of rate increase applications.

Apparently, the regulatory methods which were designed for an era of tranquility are no longer suitable under present loads. Since regulatory practices have not changed much in this decade, it has led to relatively larger regulatory lags. The regulatory lag, which results in current prices being determined by historical costs, was acting in favor of the utilities during the period 1945-

1969 because of the decreasing cost nature of the industry. However, the same regulatory lag is acting against the utilities now because of the increasing cost characteristics.

The rising electricity prices have substantially reduced the growth rate in demand. During the 1960's the electricity demand grew at 7% a year while in 1980 the electricity demand grew at 1.7% which is substantially lower than the historical 7% figure. This 1.7% rate is for the whole U.S. and in fact there are several regions in which the demand actually declined because of the large and sudden price increases.

The uncertainties about the future growth rates in demand have provided the utilities incentive to defer the construction work in progress leading to the higher book values of the plants entering the rate base. There are a number of cases in which the electric monthly bills for electrically heated homes are larger than the monthly mortgage payments for the home. The result has been increased pressure on rate commissions to make careful and lengthy investigations of utility requests for rate relief. These increased pressures have increased the delays in licensing and siting of a large capital intensive plant.

An important characteristic of the electricity business is the comparatively large capital investment which it takes to supply electricity. As of 1980, investor-owned electric utilities had invested an average of $2.63 in utility plants to support $1 in kWh sales [52]. In contrast, General Motors Corporation had a fixed asset investment of 16¢ per dollar and Exxon had an investment of 31¢ per dollar. The electric utility business is one of the most capital intensive industries. So a utility's financial situation is very important in view of its need to raise substantial amount of capital.

The combined effects of large capital requirements and rising construction costs have rendered it very difficult for electric utility companies to finance expansion out of net earnings. As shown in Table 1.5, total after-tax earnings have averaged less than 40% of construction expenditures. Moreover, the "quality" of the industry's reported net earnings has been deteriorating in one important respect--a rising fraction of earnings is the result of an accounting treatment which, in effect, credits, as net income, an imputed return on funds tied up in construction work in progress. This imputed return, called AFUDC (Allowance for Funds Used During Construction), is capitalized and included as part of the total cost of new construction. Later, when the newly constructed facilities come into service, companies may be allowed to earn a return on the capitalized AFUDC amounts and can also include the capitalized AFUDC amounts in calculating depreciation charges for rate-making purposes. Between 1970 and 1980, the AFUDC component of the industry's net earnings jumped from 20% to 54.5%. Because AFUDC is an accounting entry rather than real dollars, the industry's "cash" earnings have been lower. Since 1975, many utilities have not been able to even meet the dividend payments

Table 1.5

Electric Utility Earnings and Construction Outlays

Year	Gross Additions to Utility Plants (In Million Dollars)	After-Tax Earnings (In Million Dollars)
1950	2,050	711
1955	2,719	1,093
1960	3,331	1,557
1965	4,027	2,340
1969	8,294	2,823
1970	10,145	2,972
1975	15,090	4,859
1976	16,979	5,643
1977	19,758	6,325
1978	22,393	6,982
1979	24,378	7,552
1980	25,718 (E)	8,487

on the common stock. Also, this cash flow gap is widening. Even when all other sources of internal funds are included, most companies still have had nowhere near a sufficient internal cash flow to pay construction costs. A recent study by Charles Benore, Vice President at Paine, Webber, Mitchell and Hutchins, showed that of 225 investor-owned utilities only 53 were able to finance as much as 50% of their 1979 construction expenses with internally generated funds [52]. The industry's ratio of internal cash flow to actual construction outlays averaged 33% during the 1970's. As a result, electric utilities have depended heavily on external sources of capital. In the 1970's, investor-owned electric utilities raised a total of $113.1 billion externally; of this total, $28 billion came from new issues of common stock, $18.4 billion came from new issues of preferred stock and $66.7 billion was in the form of new long-term debt. The most recent trend in the 1970's was the use of short-term bank loans for interim construction financing because lags in rate increases have temporarily depressed earnings and blockaded access to enough long-term capital.

Due to these burdens, the utility financial outlook deteriorated as reflected by the coverage ratios. The coverage ratios indicate how safe is the investment in a firm in the form of long-term debt and preferred stock. The interest coverage ratio is defined as the ratio of the earnings before interest and taxes to interest payments, and indicates how safe is the return on debt. Similarly, preferred coverage is defined as the ratio of earnings before payment of preferred stock dividend to preferred stock dividends paid. This ratio indicates how secure the return on preferred equity of a firm is. In the 1950's and 1960's, utility interest coverages averaged about 4.0 and the preferred stock coverages averaged about 6.0, which were well above the minimums of 2.0 on bonds and 1.5 on preferred stock. Companies throughout the industry enjoyed a highly desirable degree of financial flexibility in the sense that they could select from among the most timely and economical sources of external capital. In the 1970's these comfortable coverage ratios eroded by the combined effects of higher interest rates, the large volume of new financing required and a chronic squeeze on earnings brought on by the twin effects of "regulatory lag" and sharply escalating, inflation driven cost increases. Thus, in the 1970's the utilities, by the lack of necessary coverage ratios, have used large issues of securities.

Since the mid-1970's, the electric utilities have been caught up in a vicious and financially debilitating cycle of events. The internally generated funds are insufficient to finance the construction programs so the utilities issue new bonds and preferred stock, pushing interest coverages further down. Additional capital requirements force the utilities to ask for rate increases. The rate increase is only temporary against the backdrop of highly escalating costs and the cycle starts again.

Other indicators of utility financial situation were also pointing downwards. Bonds for utilities are rated by two of the rating agencies; Standard and Poor's, and Moody's. These ratings indicate the quality of a firm's bonds. The Standard and Poor's classifies the bonds in AAA, AA, A and BBB classes. Similarly, Moody classifies the bonds in Aaa, Aa, A and Baa classes. The main financial factors considered in determining bond ratings are growth, mix, efficiency and regulatory climate. During the 1970's, Standard and Poor's downgradings of electric utility bonds totaled 128 as compared to 38 upgradings [52]. During the most part of 1970's, the utility stocks sold at an average of 60% to 90% of book value [52].

In contrast to the middle 1970's, the electric utilities are now performing relatively better, financially. The earlier downward trend has been reversed for some time, but many experts predict this is only a temporary relief. From late November, 1980 the market turned favorably for most utility stocks. From November, 1980 to early March, 1982 the price of a sample of 85 utility stocks rose 16.5% while Standard and Poor's industrial index dropped 24.3% [21]. Hence, the utilities index climed 53.9% relative to the industrial stock prices during the most recent fifteen months. Moreover, the rise has been steady with utility stock prices outperforming industrial stock prices in thirteen out of the fifteen months.

The effect of rising stock prices has been reflected in the lower stock yields for the utility stocks both in absolute and relative terms. The composite yield of a sample of 85 utility stocks dropped 1.3% from 13.1% to 11.8% in the fifteen month period [21]. This decline occurred despite the 7.5% rise in utility dividend per share. During the same period the yield on Standard and Poor's industrial index climbed from 4.6% to 6%. The combined result of these two movements has been lowering the yield spread between the two types of stocks from 8.5% to 5.8%. The utility stock yields have declined relative to the bond yields also. The utility bond yield declined 2.6% relative to the yield on Standard and Poor's index for A-rated corporate bonds.

The relatively improving performance of the utilities can be attributed to both short-term and long-term trends in the economy. From 1981 onwards the U.S. economy has been caught into a deepening recession. This recession has caused the industrial stock prices to decline. The utilities, being regulated, do not suffer as much from the recession. Their earnings outlook is comparatively healthy.

A relatively longer term cause for the improving performance of the utility stocks has been the increased prospects of disinflation. Due to the disinflation the utilities will gain on two counts. Since the interest rates can be expected to drop with a decline in the rate of inflation, utility stock yields should fall and utility stock prices should rise correspondingly. Secondly, a reduction in inflation would lessen the need for rate relief. Since utilities have more trouble in raising prices than other industrial companies to combat the effect of inflation, a slowing of inflation will be more beneficial to the utility earnings than for the earnings of most other industries.

1.3 New Frontiers for the Electric Utility Industry

The electric utility industry has not been able to achieve much in the last decade in terms of technological development. The technological development and research are very strongly linked to the future of the electric utility industry. One of the major causes for the present financial strife of the electric utilities has been the leveling off of the average boiler efficiencies. The economic advantages of interconnection and coordination also disappeared. The only long-term solution to put the electric utilities back into their stable financial situation seems to be research and technological breakthrough.

One major technological development which might revolutionize the electric utility industry is a device to store electrical energy efficiently. Presently, pumped storage offers such capabilities but it has not been very successful economically and only 2% of U.S. energy is being generated by this means. There are a number of new storage concepts which are evolving. One of these, involving the pumping of compressed air into an underground reservoir, recently became operational near Bremen, West Germany. The other such concept which might have the maximum potential is the development of rechargeable batteries. Redox system is one such battery being developed near Cleveland in NASA-Lewis laboratories. In this system the anode and cathode consist of enormous tanks full of chemicals separated by a membrane along which ion-flow occurs. The preliminary results with a working scale model indicate an impressive 70-75% rate of efficiency for the system. The use of electric storage devices can potentially make the other intermittent sources of power like solar, wind, etc. also feasible.

Another development which will have a significant impact in the future of the electric utility industry is the development of electric cars. Detroit Edison has leased converted Volkswagen Rabbits to some of its employees to determine how the average family will use and like electric cars. Fifteen small U.S. firms have already started selling a wide range of electric cars ranging from sub-compacts to station wagons. One Milwaukee firm offers a hybrid vehicle for both battery power and a gas engine. General Motors is working on an advanced nickel-zinc oxide battery that would need recharging only every 100 miles. Gulf & Western Industries has developed an electric car with its own battery and has filed a report with the Department of Energy. This car is claimed to have achieved a top speed of 64 mph and a highway driving average of 153 miles per charge.

Geothermal, solar thermal, ocean thermal, wind power also offer potential alternatives for the electric utilities. Most of these technologies have been tested at the pilot scale and with the present trends should be commercialized before the turn of the century. Environmental regulation for coal power plants has intensified the search for new coal technologies like fluidized bed boilers and combined-cycle with coal gasifier technologies.

The other trend which will be influential to the future of the electric utility industry is the increasing use of conservation. The electric utilities, whose traditional behavior has been to build rather than save, will find conservation more advantageous in future. The increasing construction costs and the diluting financial situations of the electric utility industry will be some of the factors fostering the increased use of conservation. The U.S. energy dependence on foreign countries and its inability to develop economically feasible alternative sources of energy are leading to increasing governmental and regulatory pressures on the electric utilities to undertake substantial conservation programs.

Co-generation of electricity offers another attractive alternative for the United States. With the passage of PURPA (Public Utility Regulatory Policy Act) in 1978, the incentives for co-generation by the industries have increased. The PURPA Act requires that cogeneration facilities be interconnected with transmission facilities of any utility on application by the producer. The Act states that a utility's purchase rate shall not exceed its incremental cost of an alternative energy source nor result in economic loss to any of the affected parties.

The decades to follow will exhibit an increasing use of load management techniques and marginal cost pricing principles in electric utility ratemaking. The direct load management techniques which will play a major role will be the use of time-controlled water heating, heat storage systems and load shedding devices. The use of peakload pricing principles will lead to time of day and seasonal rates and interruptible rates.

The consumer, irritated and restive about the rising costs of conventional electric service, is beginning to consider a move to some competitive alternatives. Substantial customer switching might occur in the future. In fact, electric utilities might find much of their business going to other competitors similar to that which happened to American Telephone and Telegraph Company. The electric utility industry may be forced to become more competitive than it has been in the past. As the costs of conventionally generated electricity rise, the alternative energy sources will become more economically viable. This will mean a substantial competitive force in electricity business. In fact, some expert opinion points towards the developing obsolescence of the centrally generated power [52].

CHAPTER 2

LITERATURE REVIEW

In this chapter we review the literature concerning financial and regulatory issues for an electric utility. In the first section, electric utility regulation and accounting are reviewed to highlight the important issues for a regulated electric utility in contrast to an unregulated firm. In the next section, current state of the art in modeling financial issues is reviewed. In the final section, we review some other relevant literature which will be referred in later chapters frequently.

2.1 Accounting and Regulation of Electric Utilities

Electric utilities are regulated firms. The electric utility industry has been traditionally characterized by increasing returns to scale. The above condition coupled with an inelastic demand gives rise to a monopolistic structure. Thus, an unregulated electric utility can make surplus monopoly profits at the expense of its consumers. Regulation of electric utilities is meant to be a device by which such monopoly profits can be passed to the consumers in terms of lower prices.

A typical electric utility must obtain approval from a regulatory body before it can increase the price charged to the electricity consumers. For example, consider a utility whose capital base is one million dollars and let the allowed rate of return be 10%. Then the price of the electricity fixed by the regulatory body will be such that the firm earns $100,000 over and above its operating cost of producing electricity.

The legal basis for the regulation of the public utilities ultimately rests with U.S. Constitution and its subsequent amendments. The "Commerce Clause," the "Welfare Clause" and the "Elastic Clause" are some of the important clauses guiding many important judicial opinions of the U.S. Supreme Court over the past 200 years.

An important legal problem in public utility regulation is whether the "going value" of the firm or the "book value" should be used in calculating the net worth of the firm. In most cases concerning this, the current standard seems to be the going value criterion. Leventhal cites a sequence of supporting cases [29].

In 1978, the U.S. government enacted the so-called "Public Utility Regulatory Policy Act." It is an effort by the federal government to affect the ways in which state public utility commissions regulate the retail sales of electric utility companies. Title I of the Public Utility Regulatory Policy Act (PURPA) establishes a variety of requirements and procedures for state public utility commissions to follow in establishing retail electricity rates. The objectives of PURPA are:

(i) increased conservation of electric energy.

(ii) increased efficiency in the use of facilities and resources by electric utilities, and,

(iii) equitable retail rates for electric consumers.

The act requires the state commissions to consider and determine the applicability of six specific retail rate-making standards, viz. cost of service, declining block, time of day, seasonal and interruptible rates. PURPA also establishes certain other standards concerning master metering, automatic adjustment clauses, termination of electric service, advertising and information to consumers.

For accounting purposes the electric utilities are divided into classes. The classification is based on annual revenues (see Table 2.1). The Class A and B utilities have to follow the Uniform System of Accounts. For details of the Uniform System of Accounts, see [51].

One of the important issues in electric utility accounting is that of "above" and "below" the line items. The above and below the line concept, probably, is explained best by identifying a line which is drawn beneath operating expenses in the mechanical

Table 2.1

Classification of Electric Utilities

Class	Annual Revenues (in thousand dollars)
A	2,500 or more
B	1,000 - 2,500
C	150 - 1,000
D	25 - 150

process of deducting these expenses from operating revenues. The expenses occurring and tabulated above this line are chargeable to the rate-payer since all legitimate expenses must pertain to the supplying of a utility's primary regulated service or services. Any item that is accounted for and displayed above the line will be utilized in determining the prices paid by the consumer. Although accounting does not control rate making nor rate making accounting, their mutual influence is apparent.

If expenditures are not chargeable to rate payers, the alternative is to charge them to the utility owners. For example, utility advertising for the sale of its services has been specified as below the line expense by new "PURPA" act of 1978.

Typical items which raise the question of classification as to above the line or below the line expense are:

(i) Charities
(ii) Dues to professional and nonprofessional organizations
(iii) Maintenance
(iv) Legal fees
(v) Wages and salaries
(vi) Depreciation
(vii) Taxes

Due to different alternative procedures for depreciation, accounting for tax and regulatory purposes may result in certain tax discrepancies. Those states in which a utility can normalize the tax discrepancy require that the company reflect in its financial accounting income statement a deferred income tax so that the entire federal tax expense is equal to that which the utility normally would have had to pay if it had chosen to use straight-line depreciation for both tax purposes and for financial accounting.

Over the entire life of the asset, taxes will be the same whether the utility uses a straight line or an accelerated depreciation method. The other alternative scheme of accounting which does not allow for deferred income tax account is called flow-through accounting. In the case of the flow-through accounting, the gain in terms of present value by deferring income taxes is immediately flowed through to the rate payer in terms of lower rates. In case of the normalization accounting the gain from deferred taxes is not flowed to the customers. The same methods viz. normalization and flow-through are used also to treat investment tax credit accounting.

Construction not yet completed is another important area in which the regulatory treatment differs from state to state. Some states allow all or a part of the construction work in progress (CWIP) in the rate base. Other state regulatory commissions allow the utility to accumulate an artificial book earning on construction work in progress termed allowance for funds used during construction (AFUDC). This accumulated AFUDC becomes a part of the rate base when the plant comes on line together with the initial construction costs. In most states the AFUDC rate is a little lower than the allowed rate of return, thus making firms prefer the alternative of permitting CWIP in the rate base.

The regulatory treatment of the construction work in progress and the type of accounting used for the tax discrepancies are two important regulatory factors which influence the bond ratings and the share prices of the electric utility firm. For a lucid treatment of electric utility accounting, refer to [51].

2.2 Current State of Art in Financial Modeling for Electric Utilities

In this section we review some of the financial models suitable for electric utilities. In particular, we will review the following financial models:

(i) Elton-Gruber [17] model for regulated firms

(ii) Bose [10] model for electric utilities.

(iii) Regional Electricity Model (REM) [7].

(iv) National Utilities Financial Statements (NUFS) - National Utilities Regulatory Model (NUREG) [13], [20].

The first two models represent the state-of-the-art in analyzing electric utilities investment decisions. The last two models have been used or are proposed to be used for national policy analysis.

Before we proceed to review the above models, let us review the Miller-Modigliani's [34] work on valuation of a firm in perfect capital markets. We will refer repeatedly to this work in the present and later chapters. The assumptions of Miller-Modigliani (M-M) valuation model are as follows:

(i) The firm operates in a perfect capital market in the sense that no actor in the market is large enough to influence the price of the market.

(ii) The individuals in the market are rational in the sense that everyone prefers more money to less money.

(iii) Every individual in the market has access to the same information.

Under the above set of assumptions, the arbitraging process in perfect capital markets leads to the following valuation equation for the value of an all-equity firm's security:

$$S_t = \frac{1}{(1+\rho)}[D_t + S_{t+1} - s_{Nt}].$$

Here, S_t is the share price of the security at time t and D_t and s_{Nt} denote the dividends paid and new stock issued at time t, respectively. Also, ρ is the rate of return required for a firm in the same risk class.

M-M also derive the valuation equation for a firm with debt in its capital structure. They obtain the following valuation equation:

$$S_t = \frac{1}{(1+k_t)}[D_t + S_{t+1} - s_{Nt}]$$

$$\text{where } k_t = \rho + (1-\tau)(\rho-i)\frac{B_t}{S_t} .$$

Here, ρ is the rate of return required for an all equity firm, τ is the tax rate, i is the interest rate on debt and B_t is the total debt outstanding at time t.

Elton and Gruber [17] study optimal investment and financing decisions under various forms of regulation imposed on a utility firm. They use the criterion of maximizing the wealth of initial stockholders. They also derive optimal rates of capital accumulation, rates of earnings growth in a model using Miller-Modigliani's [34] definition of the value of stockholder wealth. The Elton-Gruber [17] model uses the following variables and parameters:

$S(t)$ = market value of common equity at time t

$s_N(t)$ = the dollar amount of new stock issued at time t (new stock is issued ex-dividend)

i = interest rate on debt

$b_N(t)$ = dollar value of new bonds issued at time t

$K(t)$ = book value at time t

$B(t)$ = dollar value of bonds outstanding at time t

ρ = rate of return for an all-equity firm in equivalent risk class

$k(t)$ = rate of return to equity holders at time t

$D(t)$ = total dividends paid at time t

τ = tax rate

R = regulated rate of return

$x^{\tau}(t)$ = earnings after taxes and before interest at time t

Based on these definitions,

$$\dot{S} = kS - D + s_N \tag{2.1}$$

Equation 2.1 is the continuous time version of Miller-Modigliani's [34] equation,

$$S(t) = \frac{1}{[1+k(t)]} [D(t) + S(t+1) - s_N(t)]$$

where

$$k(t) = \rho + (1-\tau)(\rho-i) \frac{B(t)}{S(t)} \tag{2.2}$$

As shown by Miller and Modigliani [34], (2.2) is a consequence of arbitraging process in perfect capital markets. Also, the fund-flow identity for the firm is

$$x^{\tau}(t) + s_N(t) + b_N(t) = D(t) + I(t) + iB(t).$$

In the case of continuous regulation,

$$x^{\tau}(t) = R[K(t) + B(t)].$$

Combining all the relevant constraints, Elton and Gruber [17] obtain the following control problem:

$$
\begin{aligned}
&\text{Max } S(0) \\
&\dot{S} = kS - D + s_N \\
&\dot{B} = b_N \\
&\dot{K} = I - b_N \qquad\qquad (2.3) \\
&k = \rho + (1-\tau)(\rho-i)(B/S) \\
&D = x^{\tau} + s_N + b_N - I - iB \\
&x^{\tau} = R(K+B)
\end{aligned}
$$

Elton-Gruber further add a debt to equity constraint to restrict the solution space. They also study the case when there is a lag in the process of regulation.

The Elton-Gruber model exhibits an Averch-Johnson [4] type misallocation behavior in the investment decisions. However, in the case of regulation with lag, if the regulatory body sets the allowed rate exactly equal to the cost of capital, then the firm uses an efficient combination of resources. However, a major deficiency in Elton-Gruber model is that they do not enforce the constraint that utility firms are required to meet demand.

Bose [10] develops a nonlinear programming model to study the effect of regulation on a utility firm's investment decisions. Bose [10] use a discrete and finite planning horizon in the model. Some other features of the model are:

(i) Regulatory lag is explicitly modeled.

(ii) The rate-setting decision is endogenized by setting the allowed rate of return on equity as a fixed percentage of the market-required return in each period.

The nature of the Bose model has been explored by determining solutions to cases using typical parameters from the U.S. electric utility industry. In these cases, Bose places certain bounds on interest coverage, debt to equity ratios and market to book ratio. The results of the analysis are now summarized.

If the difference by which regulated rate of return exceeds the market required rate of return increases, then earnings increase and the firm uses a higher proportion of debt in its capital structure. Further, if the fraction is sufficiently large, then the money raised by new issues might be larger than investments made by the firm. In this case bonds are issued to pay dividends. Abramson and Hyman [1] claim that this is a common feature of the electric utility industry.

If the allowed rate of return is set substantially higher (20% or more) than the cost of capital, then the firm might choose a higher investment than the minimum required to meet the increase in demand. If, however, the allowed rate of return is not substantially (20%) higher than the cost of capital, then the firm will always choose the minimum required level of investment. If the allowed return is substantially higher than the cost of capital, then, after 2 or 3 periods, the level of investments will drop down to the minimum required to meet demand.

The Regional Electricity Model (REM) is a model used for national policy analysis. The model subdivides the electricity system into three submodels, namely, electricity demand, electricity supply and regulatory submodels. The interaction of the three submodels in the overall model are shown in Figure 2.1

In the Regional Electricity Model (REM), the long term forecasts of energy needs are based on year-by-year simulation. In each year the current price of electricity is used to find the electricity demand in that year. Then, the supply submodel simulates the generation and capacity planning activity. These capacity and generation plans are used in the financial-regulatory submodel to fix the price of electricity for the next year. So, the only way in which financial considerations affect the capacity plan is through the price of electricity, a price which is fed back and used in the demand submodel. What this means is that financial and regulatory considerations in period t do not affect the period t capacity plan.

The financial/regulatory model in REM can be divided into three sections. The first section maintains the equipment inventory and calculates the total funds required on new construction for each year. The second section is principally a simulation of the

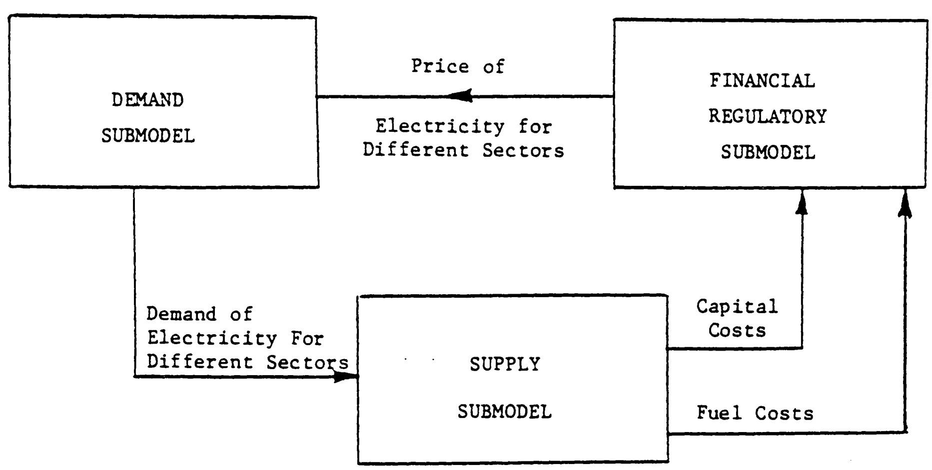

Figure 2.1. Interrelationship of Submodels in REM

regulatory procedure. It is assumed that the regulatory lag is one year. The third section estimates new financing needs.

In [26], the financial/regulatory segment of REM is assessed as a model for policy analysis. As indicated in [26], the model does not have a representation of capital markets. Instead, it uses fixed interest rates and uses interest coverage and debt ratios to limit debt financing. As indicated in [26], an important simplification made in the financial/regulatory submodel is that instead of using supply curves for the various sources of funds, fixed "rule-of-thumb" constraints are placed on the amounts of funds that can be raised from each source. To quote [26],

> "The existing submodel shows debt being available at constant cost up to a debt/asset ratio of 60 percent. No borrowing is allowed beyond that point at any cost.... In practice, utilities may be somewhat able to push up their debt-asset ratios, though by doing so, their bond ratings may drop and the interest rate they would have to pay would go up."

The National Utility Financial Statement (NUFS) [13] model takes the output from a capacity expansion planning submodel and forecasts the balance sheets and income statements and other financial tables under different regulatory policies. The model is utilized by the Department of Energy in conjunction with Midterm Energy Forecasting System (MEFS) [13]. The inputs to the model are capacity additions by plant type, operation costs, tax rates, regulatory policies about Construction Work in Progress (CWIP), capital structure and regulatory lags. The model produces income statements, balance sheets and sources and uses of funds statement. In addition, the model calculates different financial ratios like interest coverage, market to book value ratio, etc. NUFS is designed so that the user can input the alternative regulatory policies to evaluate the joint effect of regulatory policies and capacity additions.

In large part, NUFS is a series of accounting relationships that, together with the above mentioned data inputs, produces financial forecasts for the utility industry.

In [2] an evaluation of NUFS capabilities is presented. The major drawbacks of NUFS, as concluded in [2], are as follows:

- NUFS uses only historical cost method of rate base valuation. It does not incorporate the reproduction cost and the fair value rate base valuation methods.

- The components of capital are assumed to be available at a constant cost up to a user-supplied "critical point." Thus, capital supply curves are not embodied in the model.

The National Utility Regulatory Model (NUREG) [20] provides a procedure to incorporate financial considerations into capacity planning models, in particular, MEFS. Although the methodology is developed for use with regional models like MEFS, the authors of NUREG suggest that the generality of the approach makes the procedure applicable to models for capacity planning of an individual utility. The approach aims at generating capacity plans that are "financially feasible." Financial feasibility of a plan (over a given time horizon) is determined by its effect on certain financial ratios like interest coverage, rate of return on equity, etc. Thus, given a capacity plan for future time periods, the NUFS [13] model is utilized to determine the above mentioned financial ratios. The process developed in NUREG may now be summarized as follows:

- Solve a regional capacity planning problem that gives a minimum cost (presumably present valued at a specific discount rate) plan of meeting demands in the planning horizon.

- Utilizing the plan obtained above, financial statements are generated through the use of NUFS.

- If the relevant financial ratios belong to a user-specified range of acceptable ratios, then the capacity plan is declared financially feasible and the process stops. Otherwise, the following steps are executed.

- Determine limits on capital expenditure implied by the specified ranges of financial ratios. This step is performed by first estimating the sensitivity of the ratios to changes in capital expenditure and then solving a goal program that obtains feasible capital expenditures that minimizes the deviation from the initial capital expenditure stream. This yields certain limits on capital expenditures during each year in the horizon.

- Using the limits obtained in the previous step, the regional capacity planning problem is resolved with constraints on capital expenditures. The resulting plan is termed financially feasible and the process stops.

The evaluation of NUREG in this survey is confined to the conceptual basis of the approach. The data input of NUREG, in terms of ranges on different ratios, is what decides the financial feasibility of a plan. Thus, the model has the same shortcoming of not using a supply curve of funds as exhibited by REM financial segment and NUFS financial model [7 , 13].

2.3 Other Relevant Literature

In this section we will review some of the important theoretical work done in regulated economics and relevant empirical work for studying the financial markets in which the electric utilities operate. First we review Averch-Johnson's work in regulatory economics.

The Averch and Johnson [4] paper triggered the first model of theoretical and analytical interest in the process of regulation. Averch-Johnson (AJ) analyze the firm subjected to rate of return regulation. They consider the model for a profit maximizing firm subject to constraint on its profits and one which uses two factors of production viz. labor and capital. The mathematical program with which (AJ) are concerned is:

$$\text{Max } \pi = q\, p(q) - r_1 x_1 - r_2 x_2$$

$$\text{s.t. } q\, p(q) - s\, x_1 - r_2 x_2 \leqq 0$$

$$x_1, x_2 \geqq 0$$

where

x_1 = capital

x_2 = labor

r_1 = unit cost of capital

r_2 = unit cost of labor

q = $f(x_1, x_2)$ where f is the production function

s = regulated rate of return

Also, $p(q)$ is the price charged at q output quantity, i.e. $p(q)$ is the inverse demand curve. If we let λ be the Lagrange multiplier associated with the single constraint, then it is shown by (AJ) that,

$$-\frac{dx_2}{dx_1} = \frac{r_1}{r_2} - \frac{\lambda}{(1-\lambda)} \frac{(s-r_1)}{r_2}$$

Also, it can be shown that $0 \leqq \lambda < 1$, so for $s > r_1$, the firm will employ a more capital intensive technology than an unregulated monopoly which operates at a point where marginal rate of technical substitution is exactly equal to the negative of the inverse ratio of the production factor costs. The above mentioned result comes about because of the non-symmetric treatment of the factors for the purposes of regulation [5].

The empirical studies to test the existence of Averch-Johnson effect in the electric utilities appear in Emery [18], Spann [49], Courville [12], Peterson [41], Hayashi-Trapani [24], Boyes [11], Stoner-Peck [50] and Murphy-Soyster [38]. Emery [18], Boyes [11], and Murphy-Soyster [38] conclude that AJ effect in electric utilities is not significant and the other studies conclude the existence of a significant AJ effect in electric utilities.

Next, we review some of the empirical regression models to explain electric utility firms' bond ratings and share prices by various financial ratios.

Bhandari, et al. [8] study whether or not a multivariate discriminant model involving certain variables which characterize the financial status of the firm can be used to explain and predict the quality rating changes of the electric utility bonds. They show, by using 1973-74 data on bond ratings and other financial variables, that about 90% of the changes in bond ratings can be explained by the levels and trends of the fixed charge-earnings ratio, debt as a percentage of total capitalization ratio and return on assets ratio. They show that their "Bond Quality Rating Change" model was able to replicate a much higher proportion of the rating changes than the earlier models which use bond quality only.

Edelman [14] also studies a cross-sectional regression model based on data from 1968 to 1974 to replicate the bond ratings by the financial ratios. He uses a multiplicative form of the regression equation and estimates the following equation:

$$\begin{aligned}\text{Coded Ratings} = 11.065 &+ 7.817 \log_{10} (\text{coverage}) \\ &+ 1.530 \log_{10} (\text{asset size}) \\ &- 10.007 \log_{10} (\text{debt/capital ratio}).\end{aligned}$$

$$\text{Here, coded ratings are} = \begin{cases} 9 \text{ for Aaa,} \\ 7 \text{ for Aa,} \\ 5 \text{ for A,} \\ 3 \text{ for Baa.} \end{cases}$$

Pinches, et al.[44] study the statistical relationship between the bond ratings and regulatory climate, total assets, net income/total assets, earnings before interest and taxes/fixed charges, construction expenses/total assets, growth rate in net earnings variables. They show that the single most important variable describing bond ratings is the interest coverage ratio.

Wilson Associates [13] presented the following regression equation in testimony before the North Carolina Public Utilities Commission:

$$YLD = 9.535 - .1117\ (WAGDE) - .2850\ (COVR).$$

where,

YLD = dividend yield,

WAGDE = weighted average growth rate in earnings per share,

COVR = interest coverage.

The National Economic Research Association estimated a relationship between the cost of equity capital and certain financial indicators. It was used by Mr. Herman G. Roseman in testimony before the California Public Utilities Commission. He used 1973-1974 data to regress the price to book value of stock with rate of return on common equity, type of accounting used, oil as percentage of all fuels used in generation, AFUDC (allowance for funds used during construction) as a percentage of net income to stockholders. A similar equation was estimated by Trout [54] using 1977 data.

Russell Fraser [22] describes the main factors considered in Standard and Poor ratings. The main factors considered are:

(i) Growth, mix, quality, efficiency, competition and other factors influencing operations of a utility firm.

(ii) Territory, economy and energy factors.

(iii) Regulatory climate.

(iv) Construction program and financing requirements.

A recent effort in relating the bond ratings to the financial parameters appears in [13]. In [13], the utilities are classified into two groups, viz. low coverage and low internal generation group and high coverage and high internal generation group. The results indicate that the utilities in low group are less likely to have Aa bond ratings.

In conclusion, the most important variable to explain bond ratings is "interest coverage" followed by allowance for funds used during construction to total earnings. Similarly, the most important ratio explaining the equity yields for electric utilities is rate of return to common equity followed by accounting method and regulatory climate.

Some studies for estimating the cost of capital for the electric utility industry appear in Miller-Modigliani [35], Litzenberger-Rao [30], Kanhouwa [27], Mcdonald [33], Higgins [25], and Thompson [53].

The above work covers the financial and regulatory issues for an electric utility very extensively but significant work has not been done to integrate these issues in capacity planning models. The aim of the present work is to fill in this gap.

CHAPTER 3

MULTIPERIOD CAPACITY EXPANSION PLANNING MODELS

3.1 Introduction

Electric utility capacity expansion planning, like capacity planning in other industries, refers to the process of deciding what should be the capacities of different production plants in the future. In the context of electric utilities, the production plants under consideration will be coal-fired or oil-fired thermal power plants, nuclear power plants, hydroelectric plants and gas turbines, etc.

The electric utility capacity expansion planning differs from capacity planning in other industries for several reasons. The electric utilities are highly capital intensive industries as noted in Chapter 1. Due to the large amounts of capital involved, electric utility capacity expansion planning obtains paramount importance in electric utility management. Secondly, the electric utilities are regulated industries. The regulatory body requires the utilities to have enough capacity to meet demand. This puts an extra constraint on an electric utility's capacity planning. The regulation not only constrains the electric utility's capacity expansion decision, but it can also foster other than minimum cost behavior [4]. We will analyze this question in Chapter 5. Thirdly, at the present level of technology, electricity is largely a non-storable product. This implies that an electric utility's capacity should be at least equal to the peak demand on the system. This is in contrast to other industries which normally have capacity to meet the mean demand and use inventory as a buffer.

An electric utility, typically, faces a time varying demand which varies with time of the day and the season of the year. Most utilities have their peak demands during summer or winter months and the daily peak occurs in the afternoon. In Figure 3.1, a typical time pattern of demand is shown. This chronological pattern of demand can be rearranged such that the resulting arrangement is monotone nonincreasing. This monotone nonincreasing curve is called a load duration curve. Figure 3.2 shows a typical load duration curve. The load duration curve (or load curve) specifies how many hours the load was larger than a given load level L.

Normally, the duration over which a load curve is drawn is chosen to be 1 year. It is convenient to normalize the load curve by the factor of number of hours in a year. The normalization has the effect of contracting the scale on the horizontal axis by the above factor. In the sequel, we will be referring to a normalized load curve unless stated otherwise.

The electricity generating plants under consideration can be roughly characterized by a unit (annualized) capital cost ($/kW) and a unit fuel cost ($/kWh). We normalize the fuel costs also

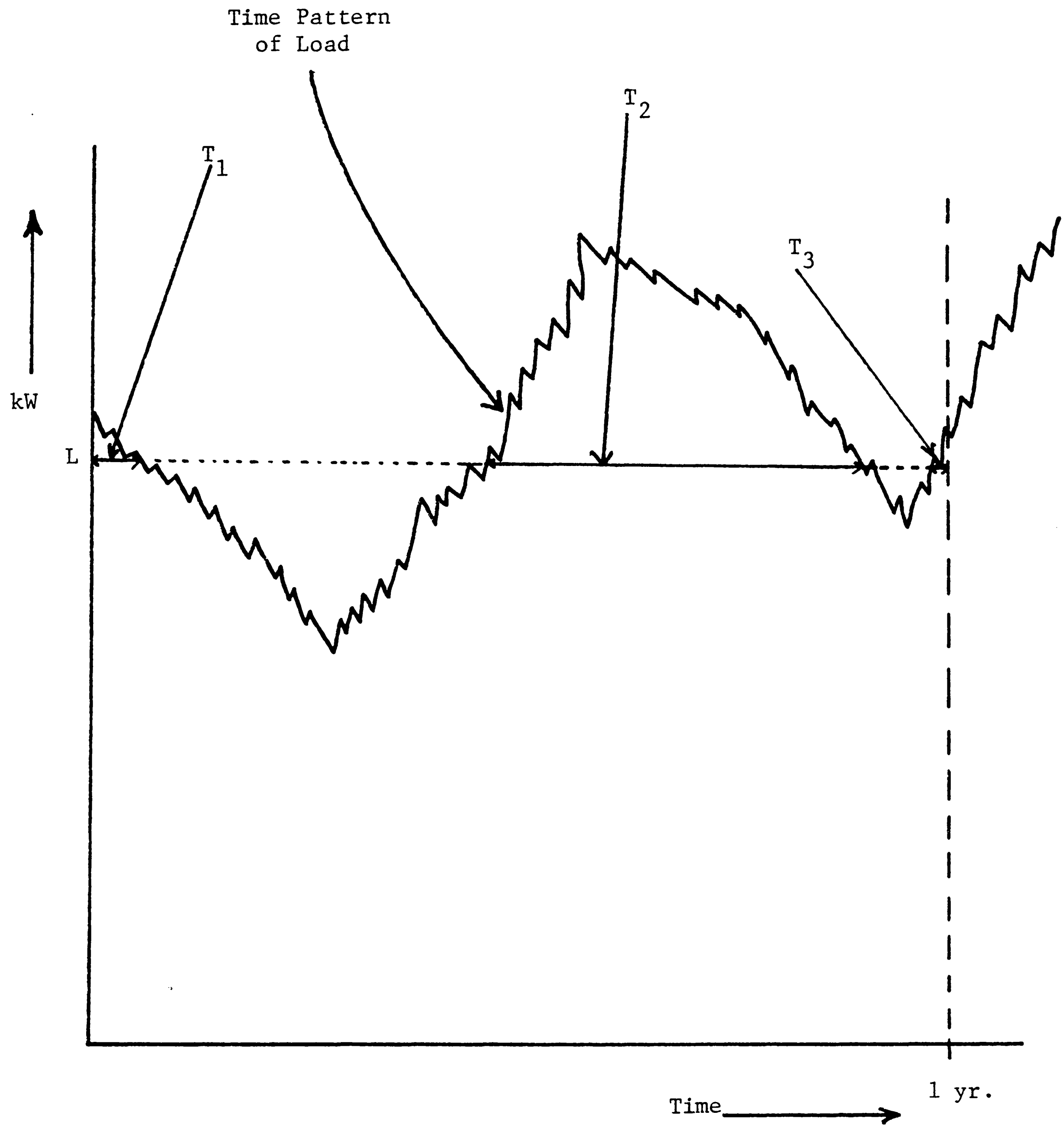

Figure 3.1. Time Pattern of Load

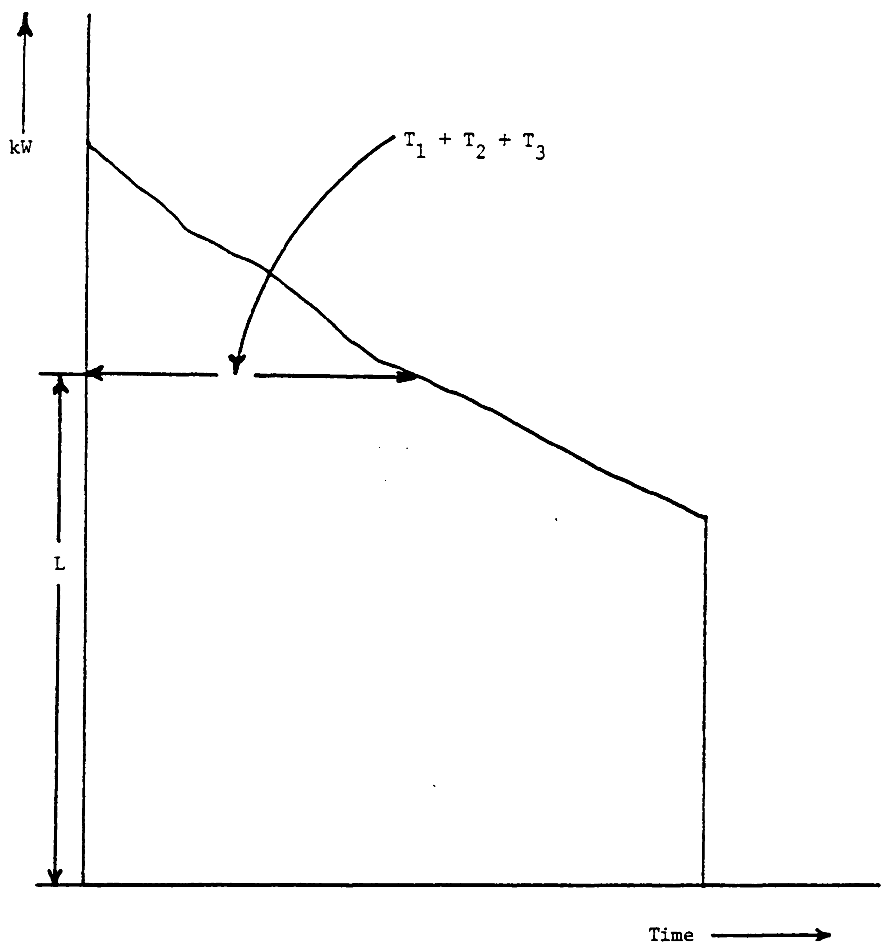

Figure 3.2. A Load Curve

by the factor of number of hours in a year. This is done to be consistent with the load curve. We will be dealing with normalized fuel costs unless stated otherwise. Let the fuel costs and capital costs be denoted by g_i and k_i for plant type i, respectively. The capacity planning problem with the above characteristizations and in its simplest form can be solved by a straight-forward breakeven analysis. A discussion of breakeven methods in the electric utility capacity planning appears in [55]. Figure 3.3a and Figure 3.3b depict the graphical analysis used to solve the capacity planning problem using breakeven chart techniques. Figure 3.3a shows the total cost (capital and fuel) of meeting 1 kW of demand for various lengths of time. The points where the lines cross, i.e., breakeven points, represent the "capacity factors" at which the utility is indifferent in using the two corresponding plant types. The breakeven points which represent the breakpoints of the "lower envelope" are the points relevant to the solution of the capacity expansion problem. The plant types for which the total cost line lies completely above the lower envelope represent "dominated" plant types. It will never be optimal to use any capacity of these plant types. A dominated plant is shown in Figure 3.4.

After removing the dominated plant types from further consideration, let the plants be numbered such that.

$$k_1 > k_2 \quad \cdots \quad > k_N$$

and

$$g_1 < g_2 \quad \cdots \quad < g_N \quad .$$

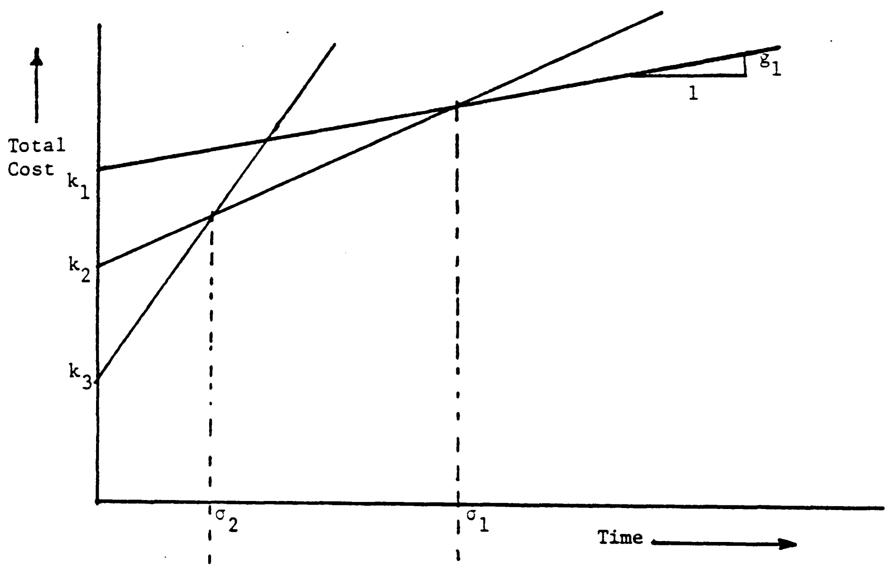

Figure 3.3a. Breakeven Chart

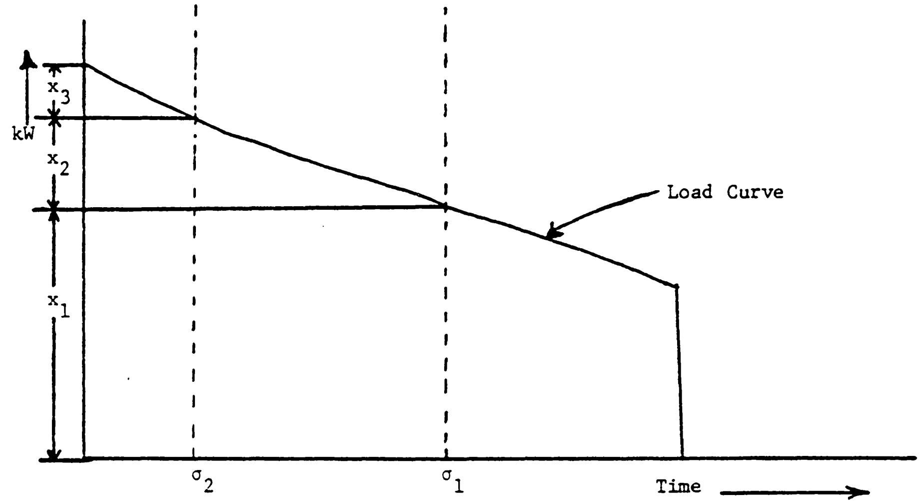

Figure 3.3b. Load Curve

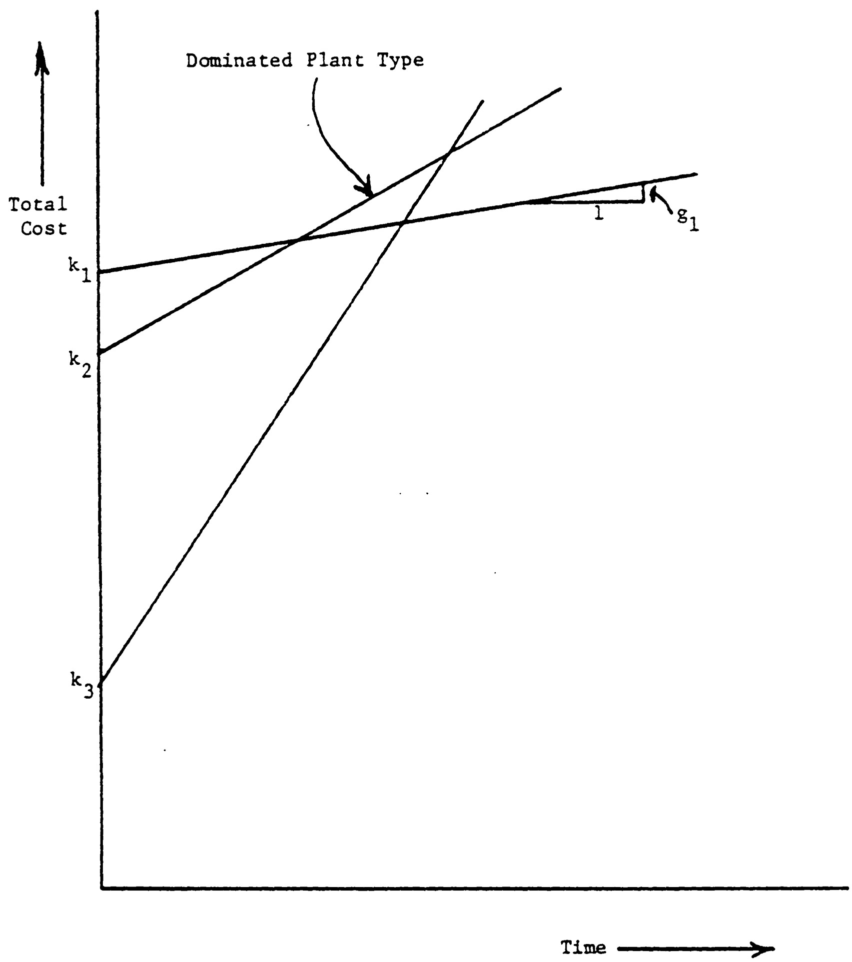

Figure 3.4. Dominated Plant Type

Here, N is the total number of nondominated plant types. Then, the breakeven points are,

$$\sigma_i = \frac{k_i - k_{i+1}}{g_{i+1} - g_i} \quad .$$

When these breakeven points are projected down on to the load curve, they yield the optimal solution as shown in Figure 3.3b.

In the above description the capital and the fuel costs are assumed to remain constant with time and the problem is called a single period problem. In contrast, if the capital and fuel costs change with time, a usual practice is to divide the planning horizon into a certain number of periods and during each of those periods the capital and fuel costs are treated as constants. Increasing the number of periods can replicate the time path of capital and fuel costs as closely as desired. It is usual also to assume the period to be 1 year in length. For the most part, we will be dealing with multiperiod problems. It should be noted that the introduction of more than one period in the problem complicates the capacity expansion problem considerably. Some of the issues which come about when one aims to solve the multiperiod problem are what should be the length of the planning horizon, what fuel and capital costs should be used for the future periods, how does one account for uncertainties? We will address these questions in Chapter 4.

It should also be noted that the above development assumes that a minimizing cost behavior characterizes the electric utility industry. We will investigate the validity of the above assumptions in Chapter 5.

3.2 Multiperiod Capacity Expansion Planning Models

Much of the earlier work in modeling multiperiod capacity planning problem use linear programming models [3 ,32]. The linear programming models use the idea of discretizing the load curves. The process of discretizing the load curve is depicted in Figure 3.5, where δ_1, δ_2 and δ_3 are the chosen mesh points. Let d_1, d_2 and d_3 be the areas of corresponding horizontal load segments. Consider a model in which x_i represents the capacity of equipment type i and let y_{ij} denote the capacity of equipment type i allocated to load segment j, i=1,2,...,N, j=1,2,3. For a single period problem the linear program can be written as follows:

$$\text{Minimize} \quad \sum_{i=1}^{N} k_i x_i + \sum_{i=1}^{N} g_i \left[\sum_{j=1}^{3} \delta_j Y_{ij} \right]$$

$$\text{s.t.} \quad -x_i + \sum_{j=1}^{3} y_{ij} \leq 0 \qquad \text{for } i=1,\ 2,\ 3,\ \ldots,\ N$$

$$\delta_j \sum_{i=1}^{N} y_{ij} = d_j \qquad \text{for } j=1,\ 2,\ 3$$

$$x,\ y \geq 0$$

The above linear programming formulation can be generalized to handle a T period problem. Let δ_1, δ_2, δ_3 be the chosen mesh points in periods t = 1, 2, ..., T. Also let d_{1t}, d_{2t}, d_{3t} be the areas of corresponding horizontal load segments in period t. Let k_{it} be the capital cost of equipment type i in period t. Also,

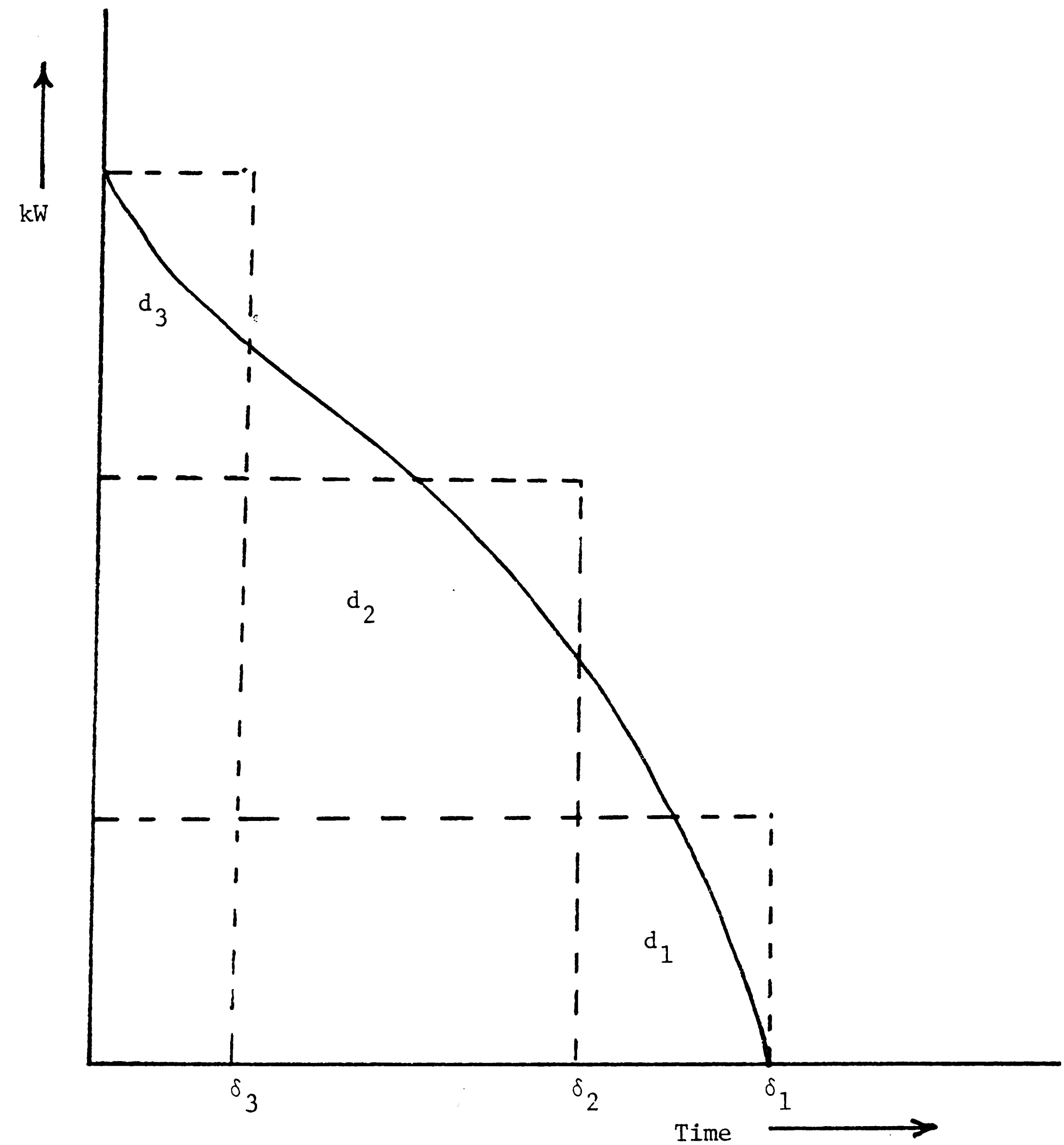

Figure 3.5. Discretizing a Load Curve

let g_{it} be the fuel cost of the fuel for equipment type i in period t. Further, let α_t be the discount factor to discount costs of period t to period 1 and denote by x_{it} the capacity of equipment type i added in period t. Also, let y_{ijt} be the capacity of the equipment type i allocated to load segment j in period t. With the above definitions, the linear programming model can be written as follows:

$$\text{Minimize} \quad \sum_{t=1}^{T} \sum_{i=1}^{N} k_{it}\, \alpha_t\, x_{it} + \sum_{t=1}^{T} \sum_{i=1}^{N} g_{it}\, \alpha_t \sum_{j=1}^{3} \delta_j\, y_{ijt}$$

$$\text{s.to.} \quad -\sum_{k=1}^{t} x_{ik} + \sum_{j=1}^{3} y_{ijt} \leqq 0 \quad \text{for } i = 1, 2, \ldots, N, \; t = 1, 2, \ldots, T$$

$$\delta_j \sum_{i=1}^{N} y_{ijt} = d_{jt} \quad \text{for } j = 1, 2, 3, \quad t = 1, 2, \ldots, T$$

$$x, y \geqq 0$$

A special case of multiperiod capacity expansion planning problem has been addressed by Grinold [23]. Grinold studies an infinite period linear programming model for capacity expansion planning.

Grinold [23] proposes the method of dual equilibrium to find the solution to an infinite period linear programming model for a capacity expansion problem. Grinold considers one type of infinite horizon program which arises in some capacity expansion planning situations. For example, consider a case in which the alternative equipment types have a three period life. In this case the infinite dimensional capacity expansion problem would exhibit the following general pattern.

$$\text{Min} \quad c \cdot x_1 + \alpha c \cdot x_2 + \dots + \alpha^{T-2} c \cdot x_{T-1} + \alpha^{T-1} c \cdot x_T + \dots$$

$$\begin{array}{llr}
\text{s.t.} & Ax_1 & \geqq b_1 \quad (u_1) \\
& Ax_1 + Ax_2 & \geqq b_2 \quad (u_2) \\
& Ax_1 + Ax_2 + Ax_3 & \geqq b_3 \quad (u_3) \\
& \quad + Ax_2 + Ax_3 + Ax_4 & \geqq b_4 \quad (u_4) \\
& \quad \ddots & \vdots \qquad \vdots \\
& Ax_{T-3} + Ax_{T-2} + Ax_{T-1} & \geqq b_{T-1} \quad (u_{T-1}) \\
& \qquad Ax_{T-2} + Ax_{T-1} + Ax_T & \geqq b_T \quad (u_T) \\
& \qquad\qquad Ax_{T-1} + Ax_T + Ax_{T+1} & \geqq b_{T+1} \quad (u_{T+1}) \\
& \qquad\qquad\quad + Ax_T + Ax_{T+1} + Ax_{T+2} & \geqq b_{T+2} \quad (u_{T+2}) \\
& \qquad\qquad\qquad \ddots & \vdots \qquad \vdots
\end{array}$$

Here $x_t \in R^N$ is a vector representing the amount of the N alternative equipment types added in period t. According to Grinold, an equilibrium condition is said to exist whenever $u_{T+1} = \alpha u_T$, $u_{T+2} = \alpha u_{T+1}$, etc. Grinold's dual equilibrium method for finding the optimal capacity expansion plan is based on the idea of modifying a truncated T period problem so that the truncated T period solution yields the same solution as the first T periods of the infinite period solution.

Soyster-Murphy [48], however, show that in the most typical cases the solution obtained by the dual equilibrium method can be obtained by annualizing the capital costs over the life of the equipment and taking the present value of that part of annualized series which falls within the planning horizon.

Many authors use a dynamic programming approach to the solution of the multiperiod capacity planning [39,40]. The work of Peterson [40] will be considered here as a relatively recent work on capacity expansion planning using a dynamic programming approach. In this effort, the author considers the years in the planning horizon as the stages for the dynamic programming formulation. The state of the system is described as the vector $S_t = (H_t, T_t, N_t, P_t)$ where,

H_t = capacity of the hydro at time t,

T_t = capacity of the thermal units at time t,

N_t = capacity of the nuclear units at time t,

P_t = peaking turbine capacity at time t.

The planner's task is to choose the level of each of the above variables for all periods t such that the discounted expected capital, operating, maintenance and penalty costs incurred during the planning horizon are minimized.

Let $f_t(S_t)$ be the present worth at time t fo the expected future costs if the system is in state S_t and the optimal policy is followed in future periods. Let $0_t(S_t)$ be the operating cost of meeting the demand if the system is in state S_t. Also, let C_t be the vector of installation costs. Then the recursive relation can be written as follows:

$$f_t(S_t) = \min_{\Delta S \geqq 0} \; [C_t \cdot \Delta S + 0_t(S_t) + f_{t+1}(S_t + \Delta S)]$$

The above recursive formulation is used to derive the dynamic optimal solution to the capacity expansion planning problem.

Another recent application of dynamic programming is found in [16]. It is a model which explicitly takes uncertainty into account. The model consists of three segments, the state of the world segment, iterative dynamic programming and dynamic programming segment. The state of the world decomposition segment separates the uncertain, dynamic generation expansion problem into a set of individual less uncertain, static problems. These static problems are made even less uncertain by the iterative dynamic programming segment, so that they can be solved by simple dynamic programming.

Dynamic programming is used in a nonconventional way in this model. The stages are various equipment types in order of increasing fuel costs. The state of the system is the cumulative installed capacity. The state-of-the-world decomposition component uses the iterative dynamic programming segment as a subroutine which in turn uses dynamic programming segment as a subroutine.

Some models use nonlinear programming to solve the multiperiod capacity expansion planning problem. One of the first efforts in applying nonlinear programming to the multiperiod capacity expansion model building to be found in the literature is by Phillips, et al. [43]. Their basic insight is based on the solution of a single period problem with existing capacities. They show that from the solution of the single period problem, a marginal value for each existing unit of each plant type can be determined. This is illustrated in Figure 3.6a and 3.6b.

Let the existing capacity of plant type 2 be loaded in the optimal solution as shown in the Figure 3.6 b. The total cost line for this old plant, shown in Figure 3.6 a, is moved parallel to itself until it reaches the dotted position where the breakeven points, projected onto the load curve, generate the optimal solution. The intercept of this dotted line on the vertical axis shown by u_2 is defined as the marginal value of this existing plant. From the Kuhn-Tucker conditions for the multi-period problem, it can be shown that the installed capacity of a certain equipment type will be optimal only if the sum of the present worths of the marginal

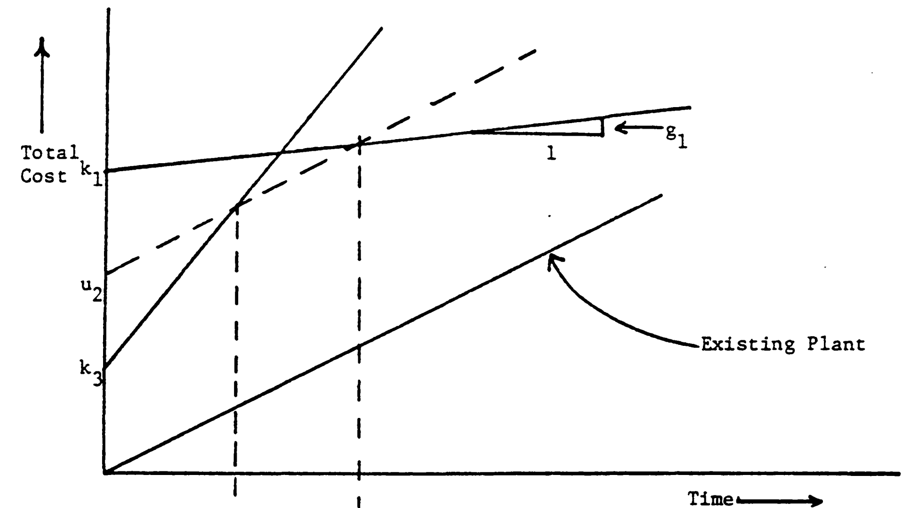

Figure 3.6a. Breakeven Chart with Existing Capacity

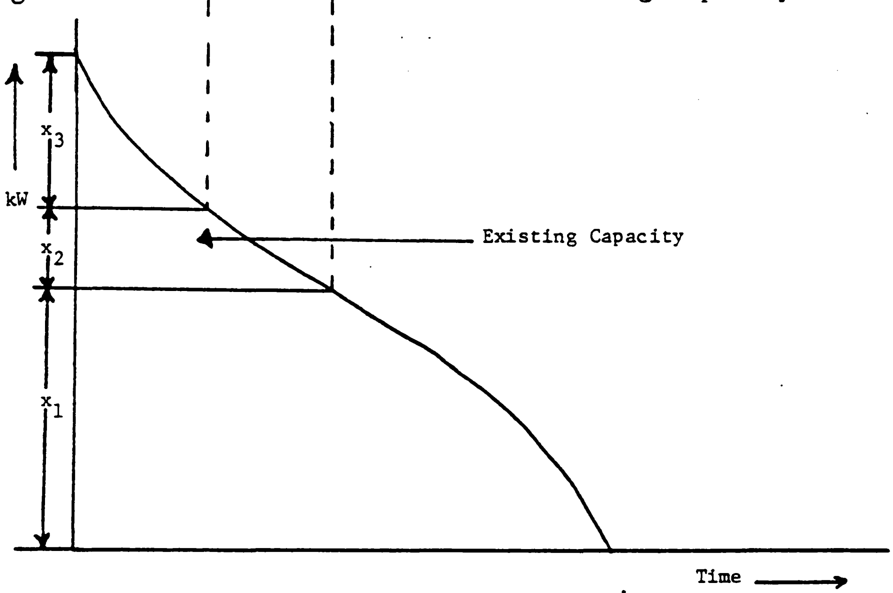

Figure 3.6b. Load Curve

values of that equipment is equal to the present worth of the annual charges on that plant. The above condition has to be satisfied for every equipment type installed in every period for a globally optimal solution. Based on the above insight, Phillips, et al., develop a solution procedure which starts by guessing at these marginal values and then these marginal values are adjusted after comparing the present worths of the annual charges with the present worths of the marginal values. They also establish the convergence properties of their solution procedure.

Another recent effort in solving multiperiod capacity planning problem using nonlinear programming techniques is by Bloom [9]. He uses a generalized Bender's decomposition to solve this problem. His procedure stems from the observation that given a set of equipment capacities, the optimal operating schedule is always in the form of the so-called merit order dispatching solution. Here, by merit order dispatching we mean that equipment type using the cheapest fuel will be loaded first to serve the demand and then the next cheapest one and so on. Thus the baseload will always be served by the least fuel intensive equipment.

In Bloom's procedure the subproblems are identical to the merit order dispatching problem. Given the capacities of the different equipment types, the optimal merit order dispatching solution is obvious but the problem is still treated as a mathematical program to calculate the shadow prices. These shadow prices are used in the generation of the generalized Benders' cut which is used in the master program. The master program turns out to be a simple linear program. Thus, in Bloom's procedure, one would first guess at the capacities and find the shadow prices from the merit order dispatching subproblems. These shadow prices are used to derive the Benders' cut. With this cut the master program is solved for a new set of capacity vectors. This process is continued until optimality is achieved.

CHAPTER 4

SOME EXTENSIONS OF CAPACITY EXPANSION PLANNING MODELS

4.1 Introduction

If one studies the multiperiod capacity expansion planning models of the last Chapter, then the following four issues emerge as major financial and regulatory considerations in capacity expansion planning model building:

(i) Is the assumption of minimizing costs the proper objective for a regulated firm?

(ii) Is the use of a single discount rate at all levels of capitalization appropriate, or, is it necessary to incorporate capital supply curves?

(iii) In a multiperiod context how does one determine what capital costs should be used in future periods?

(iv) In a multiperiod context how does one determine what fuel costs should be used in future periods?

The issues (i) and (ii) are given very scant attention in the capacity planning literature and we will address these issues in the following chapters. The issues (iii) and (iv) derive their importance because of the uncertainties about the future fuel and capital costs. Since the capital and fuel costs for future periods cannot be known with certainty, some sort of forecast of future costs must be used. These uncertainties about future fuel and capital costs have initiated the idea of using a rolling horizon strategy in capacity planning. In a rolling horizon strategy, forecasts of future fuel and capital costs for the T-period planning horizon are made and the multiperiod problem is solved. However, even though a multiperiod problem is solved, the only part of the multiperiod solution of importance is the first period decision, since this is the decision which is implemented in period one. Next, the model is incremented to period two and another T-period problem is solved with updated forecasts of fuel and capital costs. This T-period problem spans period two through T+1.

Typical forecasts of fuel and capital costs need to include considerations of at what rate these costs are going to change in the future. Thus, initial fuel and capital costs along with forecasted growth rates in these fuel and capital costs comprise the usual data assumptions about capital and fuel costs in most models. Similarly, the load curve is also forecasted by assuming some growth rate in load and, in addition, assumptions about the load curve shape must be made.

The use of a rolling horizon concept for capacity expansion planning is evident in the energy models being built at the Department of Energy and Time-Stepped Energy System Optimization Model (TESOM) at Brookhaven National Laboratory. Kydes and Ribnowitz [28] justify the time-stepped approach over clairvoyant-type approaches as follows:

> "Clairvoyant-type models use all of the information about the past, present and future in one optimization to determine the 'best' strategy for the entire horizon. An important implication of the clairvoyant-type decision-making is that all system shocks or 'surprises' such as oil embargoes or energy price jumps are foreseen and patterns of energy use are altered in anticipation of these disruptions."

One computational drawback inherent in the rolling horizon strategy is that a sequence of multiperiod problems must be solved and each one of the multiperiod problems could be quite large. Obviously, it would be advantageous to be able to shrink the size of the multiperiod problems. In particular, under what conditions, if any, could one solve a single period model, the current period, and in doing so obtain the first period part of the multiperiod optimal solution? This is the issue which we consider next.

Basically, one must determine some set of capital and fuel costs for the single period model which somehow capture their dynamic and changing behavior over time. However, that this should even be possible is not clear and often many models use some heuristically obtained surrogate fuel and capital costs. For example, Soyster and Murphy [48] suggest the use of annualized capital costs. The concept of annualization is to find that uniform series of cashflows which has the same present value over the life of the equipment as the initial outlay. The annualization process recommended by Soyster and Murphy [48] is shown in Figure 4.1.

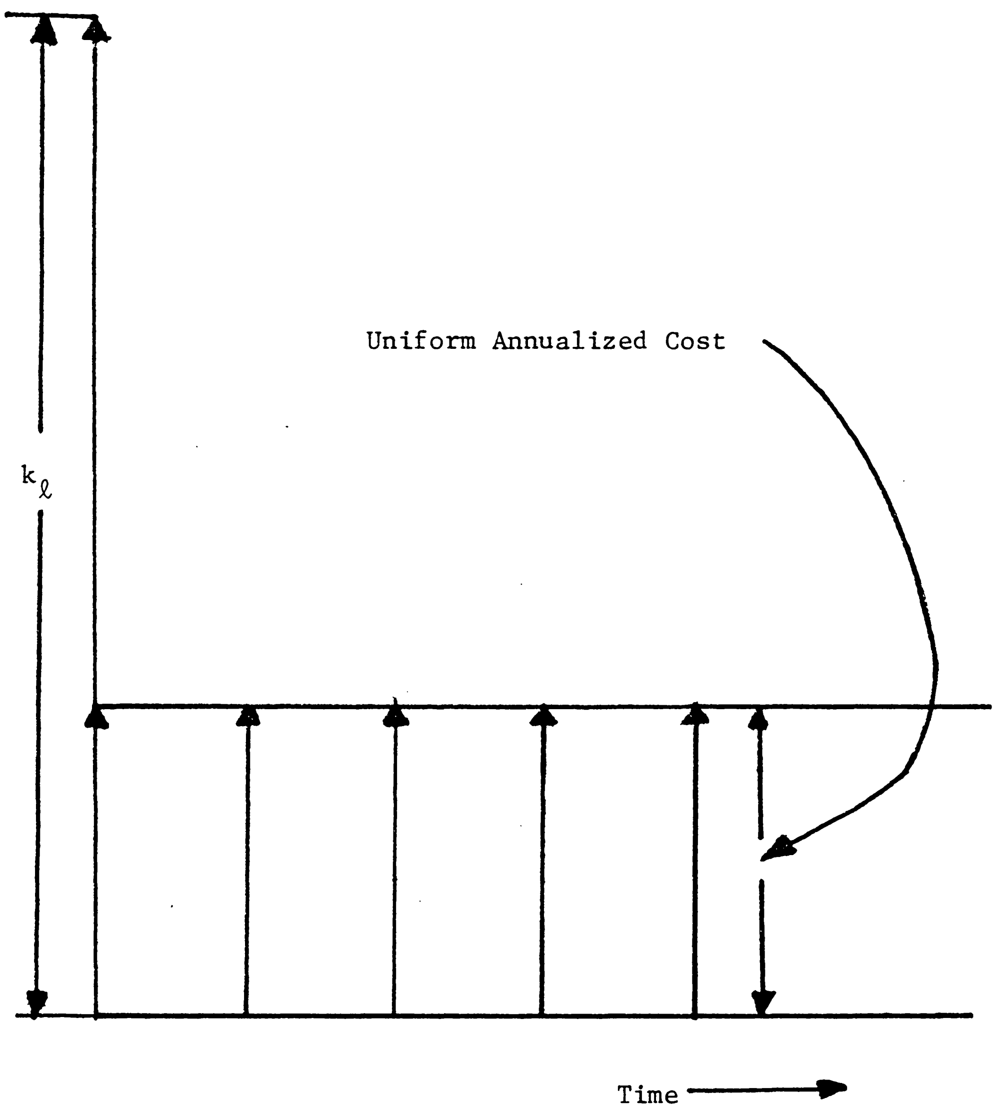

Figure 4.1. Uniform Annualization Scheme

In the next section we will show that such a process is analytically sound only if the capital costs do not change with time. When capital costs are forecasted to grow we will develop a different surrogate capital cost to be used.

Baughman-Joskow (B-J) [7] recommend certain fuel prices to use in the single period problem (breakeven chart) if one wants to replicate the first period part of the multiperiod optimal solution. (B-J) suggest a strategy to calculate a discounted average fuel price from the time pattern of future fuel prices. In the (B-J) method, one first calculates the total present value of unit fuel prices over the planning horizon as follows:

$$PV_{\ell} = g_{\ell 1} + \frac{g_{\ell 2}}{1+i} + \ldots . + \frac{g_{\ell t}}{(1+i)^{T-1}}$$

Here, $g_{\ell t}$ denotes the fuel price for equipment type ℓ in period t and i is the discount rate. Also, PV_{ℓ} denotes the present value for equipment type ℓ fuel costs for a T period horizon.

After finding PV_{ℓ}, one determines an annualized fuel price g_{ℓ}^{BJ} as given by,

$$g_{\ell}^{BJ} = PV_{\ell} \ / \ [1 + \frac{1}{1+i} + \frac{1}{(1+i)^2} + \ldots . + \frac{1}{(1+i)^{T-1}}].$$

We will show in the next section that a generalization of the above prices is optimal under certain conditions related to specific load curve shape and growth assumptions.

4.2 Appropriate Capital and Fuel Costs for Single-Period Breakeven Charts

In this section, we address the problem of selection of approprriate capital and fuel costs for a single period problem in order to replicate the first period part of the multiperiod optimal solution. First, we analyze the selection of capital costs.

Suppose the (unannualized) capital cost for equipment type ℓ is k_ℓ and it is forecasted to grow at rate α_ℓ. In other words, the initial outlays associated with installing a unit capacity of plant type ℓ in period t is $k_\ell(\alpha_\ell)^{t-1}$. Let the useful life of equipment type ℓ be n_ℓ and the discount rate be i.

If the above multiperiod problem has a solution such that the capacity of all the equipment types expand in each period, then conceivably, a sequence of single period problems should be able to solve the multiperiod problem. Now, the question arises whether Soyster-Murphy's [48] heuristically based annualization process gives rise to the first period optimal solution or not. In general, as shown in the Appendix A, the answer to the above question is no. The multiperiod problem, however, decomposes into single period (breakeven chart variety) problems under the above restriction on the optimal solution. A process analogous to uniform annualization of Figure 4.1 is suggested by the capital cost coefficients of the decomposed single period problems. This process is shown in Figure 4.2. The process suggested in Figure 4.2 is equivalent to finding that series of cashflows whose present value over the life of the equipment is k_ℓ and the terms in the series are growing at rate α_ℓ. Thus, the suggested annualization process reduced to Soyster-Murphy's uniform annualization process when $\alpha_\ell = 0$.

The appropriate capital cost to be used in the single period problem is given by,

$$\frac{k_\ell \; (i-\alpha_\ell)}{(1+i)[1 - (\frac{1+\alpha_\ell}{1+i}) \; n_\ell]} \quad ,$$

for equipment type ℓ.

The justification for the use of the above cost in the breakeven chart is, as shown in Appendix A, that when the optimal solution is such that the capacity of each equipment type expands in each period, the use of the above capital costs in a single period breakeven chart produces the first period part of the multiperiod optimal solution.

In a similar vein a "surrogate fuel price" for certain special load curve shapes and growth assumptions (see Appendix A), will also replicate the first period part of the multiperiod optimal solution. This surrogate fuel price is given by,

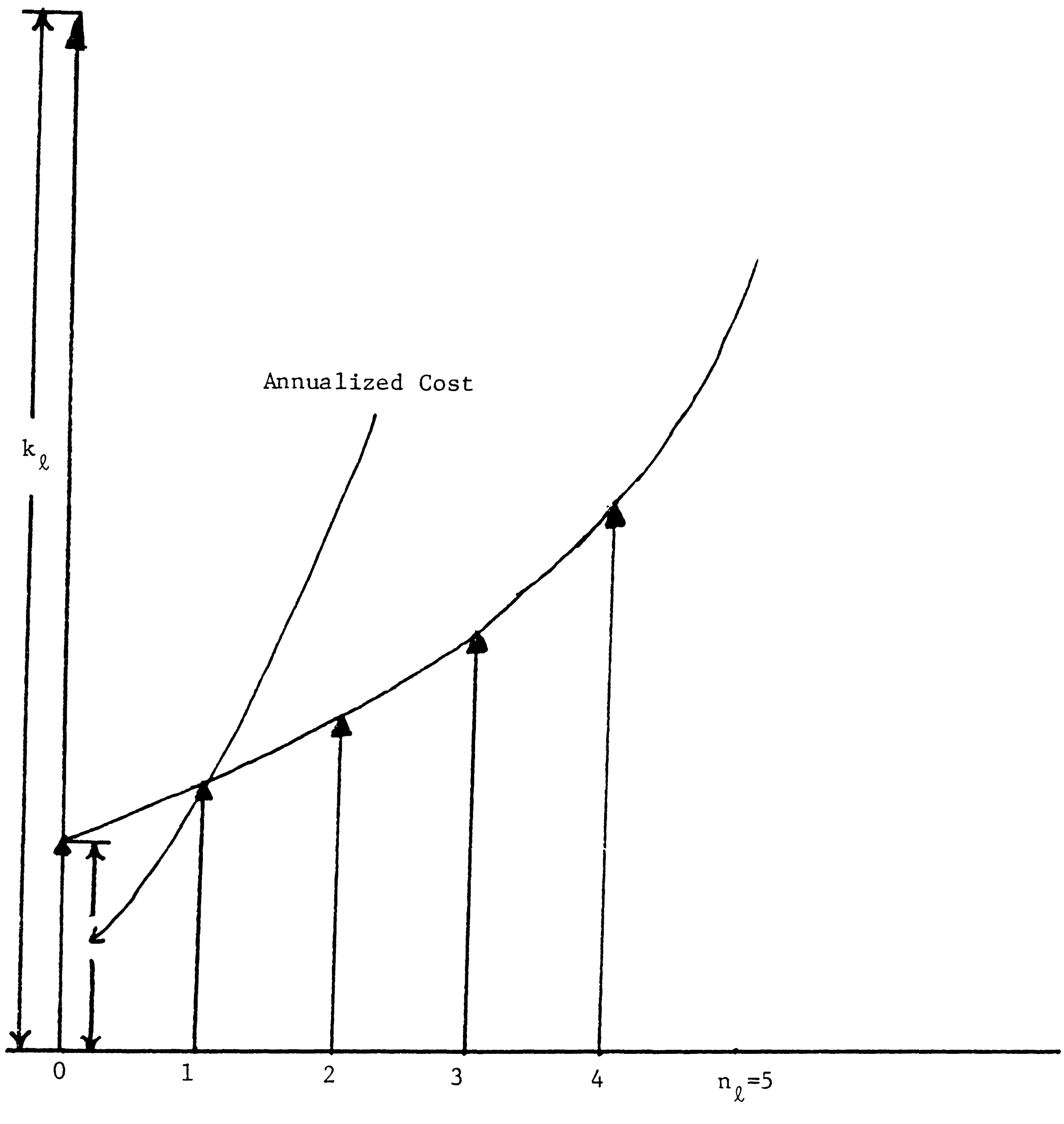

Figure 4.2. Suggested Annualization Scheme

$$g_\ell^S = \frac{g_{\ell 1}\left[\sum_{t=1}^{T} \left[\frac{\alpha}{\beta(1+i)}\right]^{t-1}\right]}{\sum^{T} \left(\frac{1}{1+i}\right)^{t-1}} \tag{4.1}$$

Here, α is the forecasted growth factor for fuel prices and $\beta < \alpha$ is the growth factor for demand. Note that as $\beta \to 1$, $g_\ell^S \to g_\ell^{BJ}$.

Here, we should again stress the meaning of the surrogate fuel price. These fuel prices are those prices which when used in a single period problem with other first period data, produce the first period part of the multiperiod optimal solution.

If the demand growth rate is larger than fuel price growth rate, i.e., $\beta \geqq \alpha$, then using current fuel prices in the single period breakeven chart is the appropriate surrogate for convex load curves (see Appendix A). Thus, for a linear load curve, the following optimal strategy is obtained:

(i) If $\beta \geqq \alpha$, then one uses current fuel prices in the single period model.

(ii) If $\alpha > \beta$, then one uses the surrogate fuel prices (4.1) in a single period model.

In both cases (i) and (ii) the single period optimal solution will replicate the first period part of the multiperiod optimal solution.

Most typical load curves will have a baseload portion. Though, the above development assumed a linear load curve but it can easily be adapted to account for the baseload portion. A load curve can typically be approximated by a trapezoidal shape as shown in Figure 4.3. Typically, it will be optimal to use the baseload type equipment, e.g., nuclear, to serve the load at capacity factor of 1.0. Thus, knowing that the rectangular segment of the loaed curve is to be served by the cheapest fuel equipment (baseload), one can translate the load curve to obtain a linear load curve as shown in Figure 4.4 and use the above strategy for finding the first period part of the optimal solution for a linear load curve. Let the optimal solution for the translated load curve be $(x_1^*, \ldots, x_N^*)$. If the baseload equipment type is numbered 1, then the optimal solution to the original trapezoidal load curve will be,

$$[x_1^* + B, x_2^*, x_3^*, \ldots, x_N^*] .$$

In the next chapter, we analyze the effect of regulation on the electric utility capacity expansion planning. Some of the extensions of the basic share price maximizing model are presented in Chapter 6. Chapters 7 and 8 are devoted to incorporating the supply curve of capital in the capacity expansion planning models.

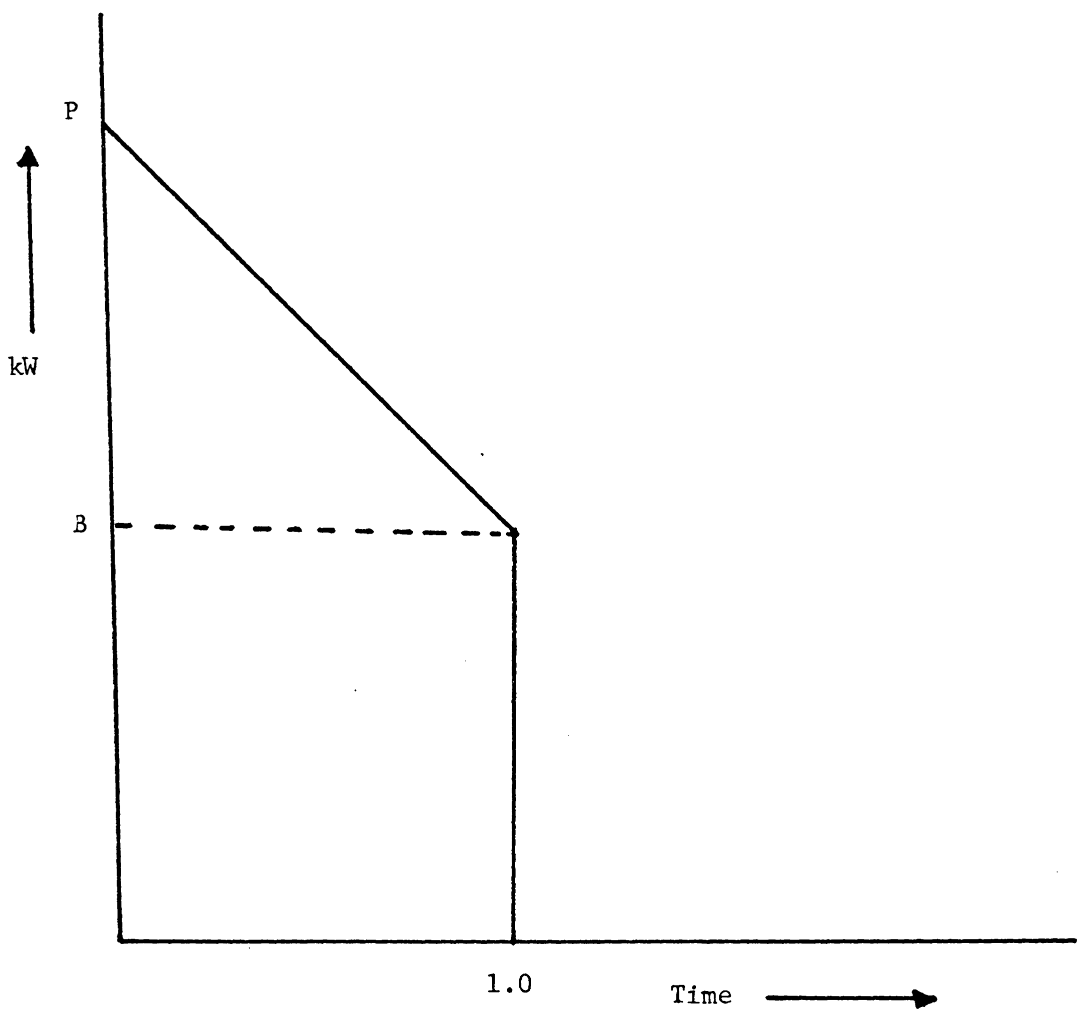

Figure 4.3. A Trapezoidal Load Curve

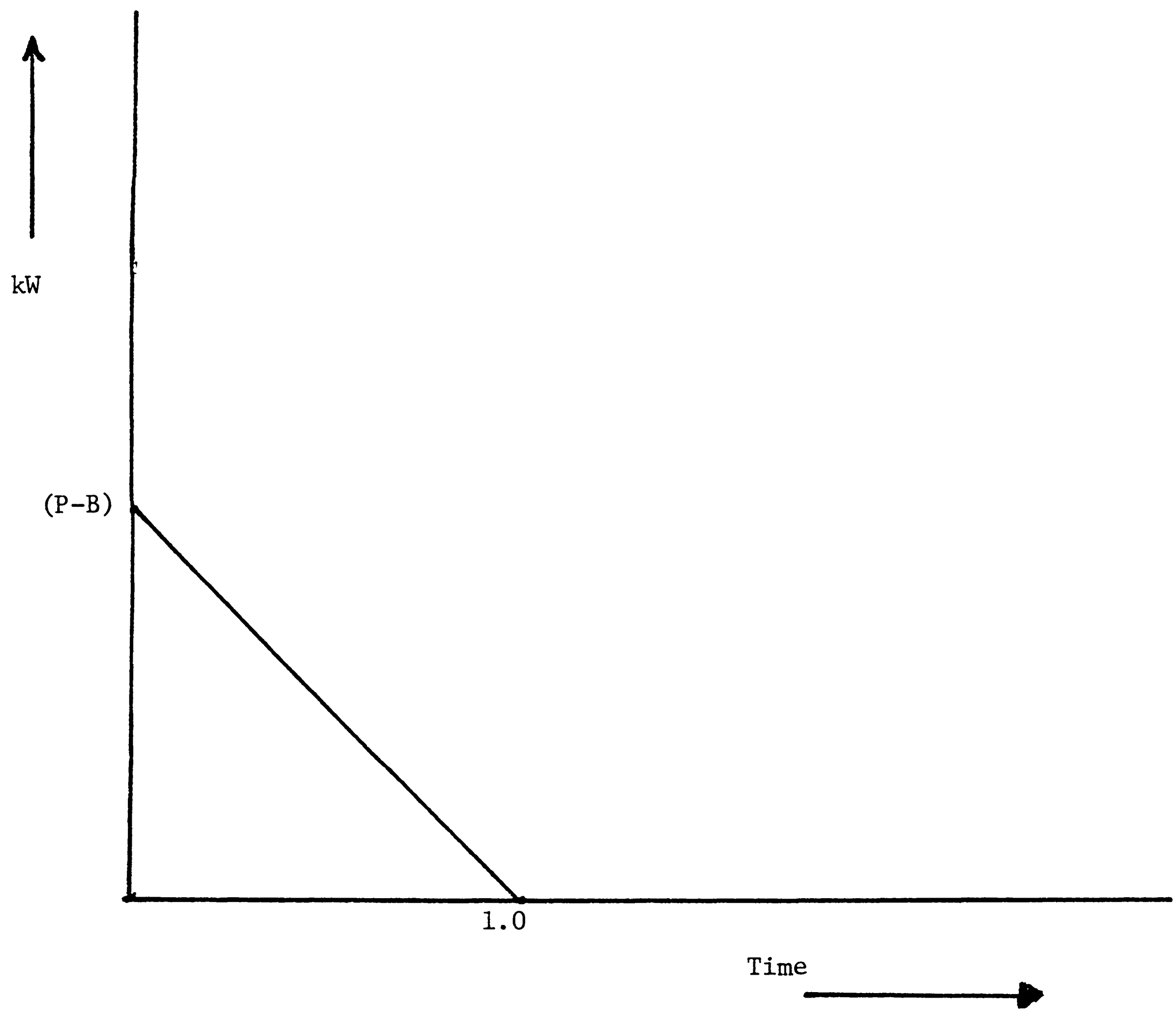

Figure 4.4. Translation of a Trapezoidal Load Curve

CHAPTER 5

VALUE MAXIMIZING CAPACITY EXPANSION PLANNING

5.1 Introduction

Most of the multiperiod capacity expansion planning models use minimization of the present value of all future costs as the objective function. In light of the discussion is section 2.3, a profit maximizing regulated firm does not necessarily choose a cost minimizing technology. In this chapter we develop a framework for electric utility capacity expansion planning in which a more rational behavior, viz., maximization of the wealth of the shareholders of the firm, is the assumed behavior of the firm.

For the United States, the value maximizing concept obtains added significance because as noted in Chapter 1, 77% of U.S. electric utility industry is privately owned. This is in contrast to other European countries where most of the electric utilities are operated by the government. Since much of the early capacity planning work originated in France and other European countries, cost minimization was a reasonable choice of the objective function.

At this point it will be convenient to restate a general form of the cost minimizing capacity expansion planning problem of an electric utility.

Let k_{it} and g_{it} be the unit capital and the unit fuel cost for the equipment type i in period t, respectively. Also assume that the equipment types are numbered such that

$$g_{Nt} > g_{N-1,t} \cdots > g_{1t} \text{ for each period}$$

$$t = 1, 2, \ldots, T.$$

Here, N is the total number of alternative equipment types. Note that we are assuming that the fuel prices remain in the same relative order over the entire horizon.

Let the load curve be discretized at points $\delta_1, \delta_2, \ldots, \delta_m$. Let d_{jt} denote the area of the load segment j in period t as shown in Figure 5.1. In Figure 5.1, f_t denotes the load curve in period t.

Let y_{it} denote the installed capacity of equipment type i in period t and let u_{ijt} denote the amount of capacity of equipment type i used to service demand in the load segment j in period t. Also, let the discount rate be ρ. With the above definitions, the linear programming capacity expansion planning model can be written as follows:

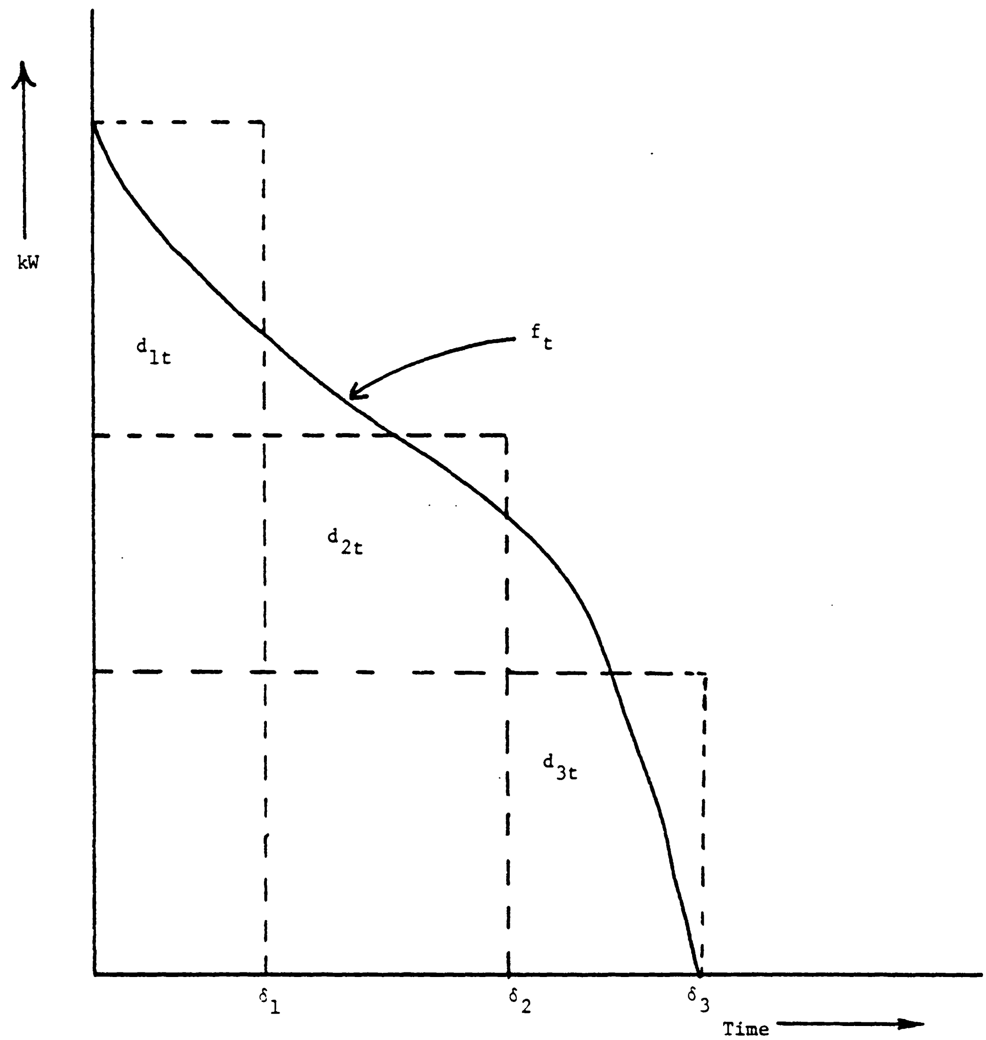

Figure 5.1. Discretizing a Load Curve

$$\text{Min} \sum_{t=1}^{T} \sum_{i=1}^{N} \frac{k_{it} y_{it}}{(1+\rho)^{t-1}} + \sum_{t=1}^{T} \sum_{i=1}^{N} \frac{g_{it}}{(1+\rho)^{t-1}} \sum_{j=1}^{m} \delta_j \, u_{ijt} \tag{5.1}$$

$$\text{s.t.} \quad - \sum_{\ell=1}^{t} y_{i\ell} + \sum_{j=1}^{m} u_{ijt} \leqq 0, \text{ for } i = 1, 2, \ldots, N.$$
$$t = 1, 2, \ldots, T.$$

$$\delta_j \sum_{i=1}^{N} u_{ijt} = d_{jt} \text{ for } j = 1, 2, \ldots, m; \; t = 1, 2, \ldots, T$$

$$y \geqq 0, \; u \geqq 0.$$

Note that the objective function is to minimize the present value of capital and fuel cost. Also, if $T = \infty$, then the infinite horizon program is:

$$\text{Min} \sum_{t=1}^{\infty} \sum_{i=1}^{N} \frac{k_{it} y_{it}}{(1+\rho)^{t-1}} + \sum_{t=1}^{\infty} \sum_{i=1}^{N} \frac{g_{it}}{(1+\rho)^{t-1}} \sum_{j=1}^{m} \delta_j \, u_{ijt}$$

$$\text{s.t.} \; - \sum_{\ell=1}^{t} y_{i\ell} + \sum_{j=1}^{m} u_{ijt} \leqq 0 \quad \text{for } i=1, \ldots, N; \; t=1, \ldots, \infty$$

$$\delta_j \sum_{i=1}^{N} u_{ijt} = d_{jt} \quad \text{for } j=1, \ldots, m; \quad t=1, \ldots, \infty \tag{5.2}$$

$$y \geqq 0, \quad u \geqq 0.$$

In section 5.3 we will present, in contrast to (5.1) and (5.2), a model whose objective function is the maximization of the value of the firm.

5.2 Assumptions of the Value Maximizing Model

The value maximizing capacity planning model to be developed in the next section is formulated under certain idealistic assumptions. Some of these assumptions will be relaxed in subsequent extensions. The most important assumptions of the value maximizing model are as follows:

(i) The firm has only equity in its capital structure.

(ii) The firm is operating in perfect capital markets so that Miller-Modigliani (M-M) [34] valuation equation is valid.

(iii) The installation of new equipment takes place instantaneously (i.e., the construction lead times are zero).

(iv) The regulatory commission mandates are implemented with a J period lag.

(v) The firm's risk class does not change with time.

(vi) The regulated rate of return does not change with time.

(vii) The price elasticity of electricity is negligible.

The extensions to relax assumptions (i) and (iii) are presented in Chapter 6.

Let us examine the last assumption in further detail. Electricity consumers can be divided into two sectors, namely, residential and industrial. Residential consumers typically exhibit a rather inelastic demand. However, industrial consumers, at times, show significant price elasticity because of their ability to substitute between different sources of energy. But, since the price of electricity is regulated, it does not fluctuate significantly, and, hence, price elasticity can be ignored, at least as a first level of approximation.

5.3 Value Maximizing Model

Our model, which we now develop, exhibits some of the characteristics exhibited by the (A-J) model [4]. However, in comparing the two models, it should be noted that in the model of this study, we are ignoring the price elasticity completely. In addition to the variables defined in Section 5.2, we define the following:

J = regulatory lag

S_t = the market value of common equity in period t

K_t = the book value of common equity in period t

s_{Nt} = the dollar amount of new common stock issued in period t. New stock is assumed to be issued ex-dividend

D_t = the total dividends paid in period t

Z_t = the total earnings of the firm in period t

I_t = the amount of investment in period t

P_t = the electricity price fixed by the regulatory commission for period t

O_t = the total operating cost in period t

ρ = the rate of return required by the shareholders of an all equity firm in the same risk class

R = the regulated rate of return

With the above definitions, (M-M)'s valuation equation [34] can be written as:

$$S_t = \frac{1}{1+\rho} [D_t + S_{t+1} - s_{Nt}], \quad \text{for all periods } t \tag{5.3}$$

Now, the objective of maximizing the wealth of the firm's current shareholders will be to maximize S_1.

From (5.3) it follows

$$S_1 = \sum_{t=1}^{\infty} \frac{1}{(1+\rho)^t} [D_t - s_{Nt}]. \tag{5.4}$$

Now, to continue our development note that the sources and uses of funds should be equal in each period. This identity can be written as

$$D_t + I_t = Z_t + s_{Nt}. \qquad (5.5)$$

From (5.4) and (5.5) one obtains

$$S_1 = \sum_{t=1}^{\infty} \frac{1}{(1+\rho)^t} [Z_t - I_t]. \qquad (5.6)$$

Since the change in the book value in period t equals the investments made in period t, it follows that

$$K_{t+1} - K_t = I_t. \qquad (5.7)$$

Also, the earnings of the firm for period t is given by

$$Z_t = P_t \int_0^1 f_t(h)dh - 0_t \qquad (5,8)$$

Here $\int_0^1 f_t(h)dh$ is the total energy demand in period t. Since there is a J period lag in the process of fixing price, the price in period t+J is

$$P_{t+J} = \frac{RK_t + 0_t}{\int_0^1 f_t(h)dh} . \qquad (5.9)$$

From (5.8) and (5.9), we obtain

$$Z_t = \frac{RK_{t-J} \int_0^1 f_t(h)dh}{\int_0^1 f_{t-J}(h)dh} + \frac{O_{t-J} \int_0^1 f_t(h)dh}{\int_0^1 f_{t-J}(h)dh} \tag{5.10}$$

Also,

$$K_{t-J} = K_1 + \sum_{\ell=1}^{t-J-1} I_\ell \text{ for } t > J \tag{5.11}$$

where K_1 is the initial book value of the firm. Let us denote $\int_0^1 f_t(h)dh$ by Q_t. From (5.10) and (5.11) one obtains,

$$Z_t = \begin{cases} (RK_{t-J} + O_{t-J}) \dfrac{Q_t}{Q_{t-J}} - O_t, \text{ for } t \leq J \\ (RK_1 + R \displaystyle\sum_{\ell=1}^{t-J-1} I_\ell + O_{t-J}) \dfrac{Q_t}{Q_{t-J}} - O_t, \text{ for } t > J \end{cases}$$

where K_0, K_{-1}, K_{-2}, ... are the book values at times 0, -1, -2, ..., etc. and are constants which are obtained from past data.

Next, assume that the demand is projected to grow/decay at a rate ν. Hence, $\dfrac{Q_t}{Q_{t-J}} = \nu^J$. Thus, the objective of maximizing S_1 is equivalent to

$$\text{Max} \sum_{t=1}^{\infty} \left[R\nu^J \sum_{\ell=1}^{t-J-1} I_\ell - I_t + \nu^J O_{t-J} - O_t \right] \Big/ (1+\rho)^t .$$

Since $(1+\rho)$ is a positive constant, the above objective is equivalent to,

$$\text{Max} \sum_{t=1}^{\infty} \left[R\nu^J \sum_{\ell=1}^{t-J-1} I_\ell - I_t + \nu^J O_{t-J} - O_t \right] \Big/ (1+\rho)^{t-1} .$$

The total investment in any period should be equal to the sum of the total installation expenditures. Hence, it follows,

$$I_t = \sum_{i=1}^{N} k_{it} \, y_{it} .$$

Similarly, operating cost in period t will be approximately same as the fuel cost which is given by

$$O_t = \sum_{i=1}^{N} g_{it} \sum_{j=1}^{m} \delta_j \, u_{ijt} .$$

In addition, analogous to program (5.1), constraints must be added to ensure that demand is satisfied. Hence, the program for capacity planning to maximize the value of the firm under the assumptions of the perfect capital markets can be written as

$$\text{Max} \sum_{t=1}^{\infty} \left[R\nu^{J} \sum_{\ell=1}^{t-J-1} I_{\ell} - I_{t} + \nu^{J} O_{t-J} - O_{t} \right] \Big/ (1+\rho)^{t-1}$$

$$\text{s.t. } I_t = \sum_{i=1}^{N} k_{it}\, y_{it}, \text{ for } t = 1, 2, \ldots \infty \qquad (5.12)$$

$$O_t = \sum_{i=1}^{N} g_{it} \sum_{j=1}^{m} \delta_j\, u_{ijt}, \text{ for } T = 1, 2, \ldots \infty$$

$$-\sum_{\ell=1}^{t} y_{i\ell} + \sum_{j=1}^{m} u_{ijt} \leqq 0, \text{ for } i=1, \ldots N;\ t=1, \ldots \infty$$

$$\delta_j \sum_{i=1}^{N} u_{ijt} = d_{jt}, \text{ for } j=1, \ldots m;\ t=1, \ldots \infty$$

$$y, u, I, O \geqq 0$$

Next, we show that program (5.12) has the same algebraic form as program (5.2). The consequences of this observation are quite profound. It follows that strategies and methods designed to solve the minimum cost capacity expansion planning can be applied to the capacity planning program in which the objective is to maximize the value of the firm to existing shareholders. The difference is that some appropriate modifications of the objective cost coefficients will be required.

By some appropriate algebraic manipulations, program (5.12) can be rearranged to obtain the following equivalent program:

$$\text{Max} \left\{ - \sum_{t=1}^{\infty} \frac{I_t}{(1+\rho)^{t-1}} \left[1 - R\nu^J \left\{ \frac{1}{(1+\rho)^{J+1}} + \frac{1}{(1+\rho)^{J+2}} + \ldots \right\} \right] - \sum_{t=1}^{\infty} \frac{O_t \left[1 - \frac{\nu^J}{(1+\rho)^J} \right]}{(1+\rho)^{t-1}} \right\}$$

s.t.

$$I_t = \sum_{i=1}^{N} k_{it}\, y_{it}, \text{ for } t = 1, 2, \ldots \infty \tag{5.13}$$

$$O_t = \sum_{i=1}^{N} g_{it} \sum_{j=1}^{m} \delta_j\, u_{ijt}, \text{ for } t = 1, 2, \ldots \infty$$

$$- \sum_{\ell=1}^{t} y_{i\ell} + \sum_{j=1}^{m} u_{ijt} \leqq 0, \text{ for } i=1, \ldots N;\ t=1, \ldots \infty$$

$$\delta_j \sum_{i=1}^{N} u_{ijt} = d_{jt}, \text{ for } j=1, \ldots m;\ t=1, \ldots \infty$$

$$y, u, I, O \geqq 0$$

Furthermore, observe that the quantity

$$1 - R\nu^J \left[\frac{1}{(1+\rho)^{J+1}} + \frac{1}{(1+\rho)^{J+2}} + \ldots \right]$$

can be simplified to

$$1 - \frac{R\nu^J}{\rho(1+\rho)^J} .$$

Hence, (5.13) reduces to

$$\text{Min} \sum_{t=1}^{\infty} \sum_{i=1}^{N} \frac{k_{it}y_{it}}{(1+\rho)^{t-1}} \left[1 - \frac{R\nu^J}{\rho(1+\rho)^J}\right] + \sum_{t=1}^{\infty} \sum_{i=1}^{N} \frac{g_{it}\left[1 - \frac{\nu^J}{(1+\rho)^J}\right]}{(1+\rho)^{t-1}} \sum_{j=1}^{m} \delta_j u_{ijt}$$

$$\text{s.t.} \; - \sum_{\ell=1}^{t} y_{i\ell} + \sum_{j=1}^{m} u_{ijt} \leqq 0, \text{ for } i=1, \ldots, N; \; t=1, \ldots \infty \qquad (5.14)$$

$$\delta_j \sum_{i=1}^{N} u_{ijt} = d_{jt}, \text{ for } j=1, \ldots, m; \; t=1, \ldots \infty$$

$$y, u \geqq 0.$$

If one compares program (5.14) with (5.2), it is evident that they are algebraically identical except that k_{it} is replaced by $k_{it}\left[1 - \frac{R\nu^J}{\rho(1+\rho)^J}\right]$ and g_{it} is replaced by $g_{it}\left[1 - \frac{\nu^J}{(1+\rho)^J}\right]$. Hence, instead of using the actual unit capital and the unit fuel costs for maximizing the value of the firm, one uses the coefficients k'_{it} and g'_{it} given by,

$$k'_{it} = k_{it}\left[1 - \frac{R\nu^J}{\rho(1+\rho)^J}\right]$$

and

$$g'_{it} = g_{it}\left[1 - \frac{\nu^J}{(1+\rho)^J}\right].$$

If the rate of growth in demand is less than the discount factor, then $\frac{\nu}{1+\rho} < 1$. In the above case, it then follows that as $J \to \infty$, $k'_{it} \to k_{it}$ and $g'_{it} \to g_{it}$. Hence, as the regulatory lag increases, the electric utility behavior, under the value maximizing assumption, tends toward the cost minimizing behavior when the growth rate in demand is less than the discount rate. This result should be compared to Bailey and Coleman [6] conclusion that as regulatory lag increases the regulated monopoly will tend toward minimizing costs.

It can be further observed that if $J = 0$ and $R = \rho$, then $k'_{it} = 0$ and $g'_{it} = 0$ and all feasible solutions to (5.14) are optimal solutions, since under these conditions the objective function becomes identically equal to zero. This is the same result as the indeterminancy of the (A-J) model when regulated rate is assumed equal to the cost of capital. If $J > 0$ and $R = \rho$ and the demand growth rate is slower than the rate of discounting, then the firm will choose a cost minimizing technology since the objective functions of (5.14) and (5.2) differ only by a positive scale factor. If $J > 0$ and the demand growth rate is faster than the rate of discounting, then the adjusted coefficients of the fuel cost are negative and hence there does not exist a single allowed rate of return which can induce cost minimizing behavior. This is in contrast to Bailey and Coleman [6] result that setting $R = \rho$ will induce cost minimization if there is some regulatory lag. This occurs because in our model the time pattern of demand is explicitly incorporated by a load curve. When the demand grows faster than the rate of discounting, the firm is induced to use another form of non-minimum cost behavior. This non-minimum cost behavior is not in the choice of technology. There are informal reasons proposed in the literature for the inefficiencies which might be fostered by regulatory lag, for example Phillips [42] (pp. 709) and MacAvoy [31]. We now investigate the above inefficiency in more detail.

5.4 Dispatching Decision for a Value Maximizing Utility

For a cost minimizing electric utility the dispatching decision is optimized by using the merit order dispatching rule. By merit order dispatching one means that given a set of capacities for different equipment types, it is always optimal, in the sense of minimizing costs, to load first the equipment type having the cheapest fuel cost, and then the next cheapest, and so on. In other words, if

$$g_{1t} < g_{2t} \cdots < g_{Nt}$$

then equipment type 1 will be loaded to serve the demand first, and if type 1 equipment cannot serve the demand alone, then equipment type 2 will be loaded and so on. A load curve with merit order loading is shown in Figure 5.2.

The merit ordering property stems from the fact that the optimal solution to program (5.1), viz. $(\overset{*}{y}, \overset{*}{u})$, will be such that $\overset{*}{u}$ is the merit order loading associated with $\overset{*}{y}$. If $(\overset{*}{y}, \overset{*}{u})$ does not satisfy the merit order dispatching property, then consider a solution $(\overset{*}{y}, \bar{u})$, where $\bar{u}$ is the merit order loading arrangement of $\overset{*}{y}$. The solution $(\overset{*}{y}, \bar{u})$ is feasible to program (5.1) and has lower objective

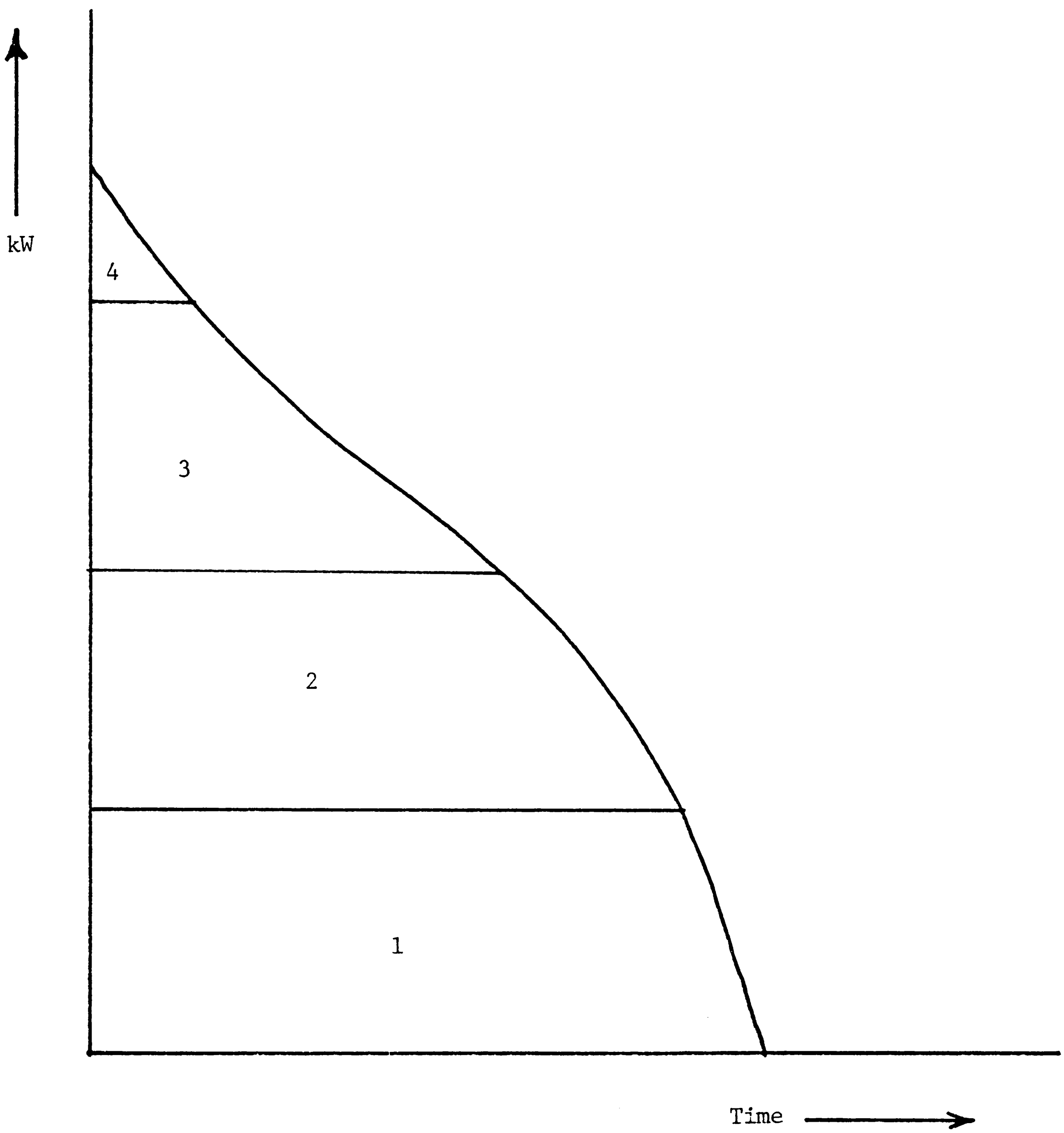

Figure 5.2. Merit Order Loading Arrangement

value so $(\overset{*}{y}, \overset{*}{u})$ cannot be optimal. Hence, the optimal solution to the program (5.1) will always be such that the merit order dispatching property is satisfied.

Similarly, for the program (5.14) the optimal solution will be such that it satisfies the merit ordering property in terms of the adjusted fuel cost coefficients, g'_{it}. However, the merit order for g'_{it} need not be the same as g_{it}. In particular, if $\nu < 1+\rho$, we have $1 - \dfrac{\nu^J}{(1+\rho)^J} > 0$, so the fuel cost coefficients g'_{it} will be in the same merit order as g_{it}. On the other hand, if $\nu > (1+\rho)$, the merit order of g'_{it} will be exactly reversed than that of g_{it}, For example, consider a utility faced with the choice of the equipment type, say coal and oil fired plants. A value maximizing electric utility, based upon our assumptions, will load the oil fired plants as the baseload and the coal fired plants as the peak-load if the demand is forecasted to grow faster than the discount rate.

CHAPTER 6

EXTENSIONS OF THE BASIC VALUE MAXIMIZING MODEL

6.1 Introduction

In this chapter we relax some of the idealistic assumptions made in the model of Chapter 5. In particular, in section 6.2 we analyze the value maximization capacity planning in a world with taxes and debt-financing. The existence of taxes makes a significant difference in the two forms of capital, viz., debt and equity because the former is tax deductible but the latter is not. In section 6.3, we will study the effect of fuel adjustment clauses. In section 6.4, we incorporate finite equipment lifetimes and nonzero lead times for construction. In section 6.5, we analyze the case when the risk class of the utility changes with time. It turns out that the assumptions (i), (iii), and (v) of Chapter 5 can be relaxed without modifying the structure of the program significantly. On the other hand, the assumptions (ii), (vi) and (vii) are more crucial and violation of any of them will lead to a substantially more complex mathematical program.

6.2 Capacity Expansion Planning with Taxes and Debt-Financing

Consider the following variables in addition to those in Chapter 5:

B_t = amount of total debt in period t

ρ_{et} = yield on equity in period t

r = interest rate on debt

τ = tax rate

We assume that τ and r do not change with time. The Miller-Modigliani's valuation equation in this case is

$$S_t = \frac{1}{1+\rho_{et}} [D_t + S_{t+1} - s_{Nt}]$$

where

$$\rho_{et} = \rho + (1-\tau)\ (\rho-r)\ \frac{B_t}{S_t}\ .$$

It then follows that

$$S_t = \frac{1}{1+\rho + (1-r)(\rho-r)\frac{B_t}{S_t}} \ [D_t + S_{t+1} - s_{Nt}\ ]$$

which reduces to

$$S_t = \frac{1}{1+\rho} [D_t + S_{t+1} - s_{Nt} - (1-\tau)\ (\rho-r)\ B_t\ ]. \tag{6.1}$$

If we denote the new bonds issued in period t by b_{Nt}, the funds flow identity can be written as:

$$D_t = Z_t^\tau + s_{Nt} + b_{Nt} - I_t \tag{6.2}$$

where Z_t^τ is the earnings after taxes. Hence,

$$Z_t^\tau = (1-\tau) \left[P_t \int_0^1 f_t(h)dh - O_t - r\, B_t \right] . \tag{6.3}$$

The regulatory body fixes the price with a lag of J periods such that the earnings after taxes and before interest are exactly R times the rate base. Mathematically, the above process of fixing price is

$$P_{t+J} = \frac{\dfrac{R(K_t + B_t) - r\, B_t}{1-\tau} + O_t + r\, B_t}{\int_0^1 f_t(h)dh} \tag{6.4}$$

The price P_{t+J} is such that if it was fixed without lag for period t then the utility would have earned exactly R times the rate base after taxes and before interest.

We also have the following identities:

$$K_{t+1} - K_t = I_t - b_{Nt} \tag{6.5}$$

and

$$B_{t+1} - B_t = b_{Nt} \quad . \tag{6.6}$$

Now, the value maximizing capacity expansion planning problem can be written as follows:

$$\text{Max} \sum_{t=1}^{\infty} \left[Z_t^{\tau} - I_t + b_{Nt} - (1-\tau)\ (\rho-r)\ B_t \right] \Big/ \ (1+\rho)^{t-1}$$

s.t.

$$B_t = B_1 + \sum_{\ell=1}^{t-1} b_{N\ell}$$

$$K_t = K_1 + \sum_{\ell=1}^{t-1} I_\ell - \sum_{\ell=1}^{t-1} b_{N\ell}$$

$$Z_t^{\tau} = (1-\tau) \left[P_t \int_0^1 f_t(h)dh - O_t - r\ B_t \right] \tag{6.7}$$

$$P_{t+J} = \frac{\dfrac{R[K_t + B_t] - r\ B_t}{(1-\tau)} + O_t + r\ B_t}{\int_0^1 f_t(h)dh}$$

$$I_t = \sum_{i=1}^{N} k_{it}\ y_{it}$$

$$O_t = \sum_{i=1}^{N} g_{it} \sum_{j=1}^{m} \delta_j\ u_{ijt}$$

$$- \sum_{\ell=1}^{t} y_{i\ell} + \sum_{j=1}^{m} u_{ijt} \leqq 0$$

$$\delta_j \sum_{i=1}^{N} u_{ijt} = d_{jt}$$

$$y,\ u,\ I,\ K,\ P,\ B,\ b_N \geqq 0 \quad .$$

If we assume that the demand grows at a rate ν, i.e.,

$$\frac{\int_0^1 f_t(h)dh}{\int_0^1 f_{t-J}(h)dh} = \nu^J ,$$

then we can simplify the program (6.7) by eliminating P_t, K_t, B_t, Z_t^τ variables. The simplified program is as follows:

$$\text{Max} \sum_{t=1}^{\infty} \frac{I_t}{(1-\rho)^{t-1}} \left[-1 + \frac{\nu^J R}{(1+\rho)^J}\right] + (1-\tau) \sum_{t=1}^{\infty} \frac{0_t}{(1+\rho)^{t-1}} \left[-1 + \frac{\nu^J}{(1+\rho)^J}\right]$$

$$+ \sum_{t=1}^{\infty} \frac{b_{Nt}\ \tau}{(1+\rho)^{t-1}} \left[1 - \frac{\nu^J r}{\rho(1+\rho)^J}\right]$$

s.t.

$$I_t = \sum_{i=1}^{N} k_{it}\, y_{it} \qquad (6.8)$$

$$0_t = \sum_{i=1}^{N} g_{it} \sum_{j=1}^{m} \delta_j\, u_{ijt}$$

$$- \sum_{\ell=1}^{t} y_{i\ell} + \sum_{j=1}^{m} u_{ijt} \leqq 0$$

$$\delta_j \sum_{i=1}^{N} u_{ijt} = d_{jt}$$

$$I,\ b_N,\ 0,\ y,\ u \geq 0 .$$

In the above program since b_{Nt} does not appear anywhere in the constraint set except the nonnegativity constraints, if $\left[1-\frac{\nu^J r}{\rho(1+\rho)^J}\right] < 0$, then the optimal solution will be such that $b_{Nt}=0$ for all t. If one eliminates

I_t and O_t in terms of y_{it} and u_{ijt} one can obtain the following cost coefficients:

$$k'_{it} = k_{it} \left[1 - \frac{\nu^J R}{\rho(1+\rho)^J} \right]$$

and,

$$g'_{it} = g_{it}\ (1-\tau) \left[1 - \frac{\nu^J}{(1+\rho)^J} \right]$$

On the other hand, if $\left[1 - \frac{\nu^J r}{\rho(1+\rho)^J} \right] > 0$ then the solution is unbounded. This is the same situation as exhibited by (M-M) [36] model of an unregulated firm in a world with taxes. M-M [37] suggest use of some institutional constraint, e.g., debt to equity ratio constraint to limit the solution. In our case, since the firm is regulated it will be most logical to assume that the regulatory body will not allow more debt in the rate base than the total investments undertaken. Thus, we can impose a constraint of the form,

$$I_t \geqq b_{Nt}.$$

With the above constraint if $\left[1 - \frac{\nu^J r}{\rho(1+\rho)^J} \right] > 0$ it follows that $b_{Nt} = I_t$. Hence, the objective function of program (6.8) can be written as,

$$\sum_{t=1}^{\infty} \frac{I_t}{(1+\rho)^{t-1}} \left[-1 + \tau + \frac{\nu^J R}{\rho(1+\rho)^J} - \frac{\tau\nu^J r}{\rho(1+\rho)^J}\right] + \sum_{t=1}^{\infty} \frac{O_t(1-\tau)}{(1+\rho)^{t-1}} \left[-1 + \frac{\nu^J}{(1+\rho)^J}\right]$$

If one eliminates I_t and O_t in terms of y_{it} and u_{ijt} one can obtain the following cost coefficients:

$$k'_{it} = k_{it} \left[1 + \frac{\tau\nu^J r}{\rho(1+\rho)^J} - \tau - \frac{\nu^J R}{\rho(1+\rho)^J}\right]$$

$$g'_{it} = g_{it} \left[(1-\tau) \left(1 - \frac{\nu^J}{(1+\rho)^J}\right)\right] .$$

The above cost coefficients are very important from a computational point of view. If one uses the modified capital and fuel coefficients as documented by the above formulae and uses the minimum cost capacity planning routines one can replicate the value maximizing behavior. In view of the fact that there exist fast solution techniques for the minimum cost capacity expansion planning, the above development implies the potential use of these routines to the value maximizing capacity expansion planning.

The above framework for analyzing the value maximizing capacity expansion planning can be utilized to answer the question whether cost minimization or value maximization best replicates the behavior of the electric utility firms.

Let us now analyze the rate setting process for policy implications for regulatory authorities. One goal of regulatory authority is to induce the firm to utilize the minimum cost technology. If demand growth rate is smaller than the discount rate, i.e., $\nu < 1 + \rho$, then for a risk averse capital market, the following condition holds

$$1 - \left[\frac{\nu^J r}{(1+\rho)^J \rho}\right] > 0 .$$

Hence the factors by which the capital and fuel cost coefficients are to be modified are positive. In this case, to induce minimum cost behavior, R should be such that,

$$1 + \frac{\tau \nu^J r}{\rho(1+\rho)^J} - \tau - \frac{\nu^J R}{\rho(1+\rho)^J} = (1-\tau) \left[1 - \frac{\nu^J}{(1+\rho)^J}\right] .$$

On simplification one obtains

$$R = \rho(1-\tau) + \tau r \qquad (6.9)$$

The equation should be compared with the Elton and Gruber [17] result,

$$R = \rho - \tau\ (\rho - r)\ \frac{\theta}{1+\theta}\ , \qquad (6.10)$$

where θ is the maximum limit on debt to book value of equity ratio. In our model we did not impose any such constraint. Note that in (6.10) if $\theta \to \infty$ $R \to [\rho(1-\tau) + \tau r]$ which indicates that our result is consistent with Elton-Gruber [17] result.

In the case when the demand growth rate is greater than the rate of discounting the coefficient for the fuel cost will be negative and, as in section 5.3, there does not exist a single rate of return which can induce cost minimizing behavior for all technological parameters.

In the next section we study the effect of fuel adjustment clauses on the above development.

6.3 Capacity Planning and Fuel Adjustment Clauses

Most regulatory commissions allow the electric utilities to pass the increased fuel costs to its consumers through the use of a fuel adjustment clause. Thus, a fuel adjustment clause is aimed to combat some of the undesirable effects of administrative delays associated with the process of regulation.

The regulatory process of fixing price with fuel adjustments is described by the following regulation:

$$P_{t+J} = \frac{RK_t}{\int_0^1 f_t(h)dh} + \frac{O_{t+J}}{\int_0^1 f_{t+J}(h)dh}$$

The above equation should be compared with equation (5.9) without fuel adjustments. Note that in this case, current price, P_{t+J}, is determined by current fuel price and a lagged capital component. If one carries out the development analogous to that of section 5.3, it is straightforward to show that

$$k'_{it} = k_{it} \left[1 - \frac{R\nu^J}{\rho(1+\rho)^J} \right]$$

$$g'_{it} = 0$$

The coefficient $g'_{it} = 0$ implies that the firm is indifferent to fuel costs in its selection of technology. Further, it should be noted that if $1 - \frac{R\nu^J}{\rho(1+\rho)^J} < 0$, then the firm will use the most capital intensive equipment and if $1 - \frac{R\nu^J}{\rho(1+\rho)^J} > 0$, the firm will use the least capital intensive equipment. Hence, if the regulatory lag is sufficiently large, then the firm will exhibit a negative Averch-Johnson effect even if $R > \rho$.

In the next section we incorporate finite equipment lifetimes and lead times on construction.

6.4 Incorporating Lead Times and Finite Equipment Lifetimes

The model of section 5.3 is developed under the assumptions of zero lead times and infinite equipment lifetimes. In this section we extend the all-equity model of section 5.3 to the cases of non-zero lead times and finite equipment lifetimes. The model of section 6.2 can also be extended to the cases of non-zero lead times and finite equipment lifetimes, but it will not be presented here.

First, let us consider the non-zero lead time case. Let the construction lead time on equipment type i be ℓ_i. Also, let the cash outflows associated with installing 1 kW of capacity of equipment type i in periods (t+1), (t+2) ...., $(t+\ell_i)$ be k_{it1}, k_{it2}, ..., $k_{it\ell_i}$, respectively. With these definitions one can write,

$$I_t = \sum_{i=1}^{N} \sum_{v=1}^{\ell_i} k_{i,t-v,v}\, y_{i,t-v}.$$

If one uses the above definition of I_t in program (5.13) instead of $I_t = \sum_{i=1}^{N} k_{it}\, y_{it}$, one obtains the following program:

$$\text{Min} \sum_{t=1}^{\infty} \sum_{i=1}^{N} \sum_{v=1}^{\ell_i} \frac{k_{i,t-v,v}\, y_{i,t-v}}{(1+\rho)^{t-1}} \left[1 - \frac{R\nu^J}{\rho(1+\rho)^J}\right] + \sum_{t=1}^{\infty} \sum_{i=1}^{N} \frac{g_{it}}{(1+\rho)^{t-1}} \left[1 - \frac{\nu^J}{(1+\rho)^J}\right] \sum_{j=1}^{m} \delta_j\, u_{ijt}$$

$$\text{s.t.} \; - \sum_{v=1}^{t-\ell_i} y_{iv} + \sum_{j=1}^{m} u_{ijt} \leqq 0, \text{ for } t = 1, \ldots \infty,\ 1 = 1, \ldots N$$

$$\delta_j \sum_{i=1}^{N} u_{ijt} = d_{jt}, \text{ for } j = 1, \ldots m,\ t = 1, \ldots \infty \qquad (6.11)$$

$$y, u \geqq 0$$

The first term in the objective function of program (6.11) can be simplified as,

$$\sum_{t=1}^{\infty} \sum_{i=1}^{N} \left[\sum_{v=1}^{\ell_i} \frac{k_{itv}}{(1+\rho)^v} \right] \frac{y_{it}}{(1+\rho)^{t-1}} \left[1 - \frac{R\nu^J}{\rho(1+\rho)^J} \right]$$

The term $\sum_{v=1}^{\ell_i} \frac{k_{it}}{(1+\rho)^v}$ can be interpreted as the present value of outflows associated with installing 1 unit of the capacity type i in period t. From the above expression, it is clear that the capital cost coefficient to be used is given by,

$$k'_{it} = \left[\sum_{v=1}^{\ell_i} \frac{k_{itv}}{(1+\rho)^v} \right] \left[1 - \frac{R\nu^J}{\rho(1+\rho)^J} \right]$$

An inspection of program (6.11) reveals that not only the capital cost coefficients are different than in program (5.14) but also the constraint set is changed.

Let us now consider the case when the equipment types have finite lifetime. Let the equipment type i have a life equal to n_i periods. Then the constraint,

$$- \sum_{\ell=1}^{t} y_{i\ell} + \sum_{j=1}^{m} u_{ijt} \leq 0$$

is modified as follows:

$$- \sum_{\ell=t-n_i}^{t} y_{i\ell} + \sum_{j=1}^{m} u_{ijt} \leq 0$$

6.5 Capacity Planning When Risk Class Changes with Time

As the risk class of the firm changes with time, the required rate of return will also change with time. Thus, to describe the above phenomena the parameter ρ should be made dependent on time. In other words, instead of having ρ as a constant we will now have ρ_t as the required rate of return for an all equity firm at time t. Now (M-M)'s valuation equation is:

$$S_t = \frac{1}{1 + \rho_t} [D_t + S_{t+1} - s_{Nt}] .$$

Substituting recursively S_1 can be obtained as,

$$S_1 = \sum_{t=1}^{\infty} \frac{[D_t - s_{Nt}]}{\prod_{\ell=1}^{t} (1+\rho_\ell)} = \sum_{t=1}^{\infty} \frac{[Z_t - I_t]}{\prod_{\ell=1}^{t} (1+\rho_\ell)} .$$

Carrying out the analysis of section 5.3, the following objective function for the value maximizing capacity expansion planning can be obtained:

$$\text{Min} \sum_{t=1}^{\infty} \sum_{i=1}^{N} \frac{k_{it}\, y_{it}}{\prod_{\ell=1}^{t} (1+\rho_\ell)} \left[1 - R\nu^J \left\{ \sum_{q=1}^{\infty} \frac{1}{\prod_{\ell=t+1}^{t+q} (1+\rho_\ell)} \right\} \right]$$

$$+ \sum_{t=1}^{\infty} \sum_{i=1}^{N} \frac{g_{it}}{\prod_{\ell=1}^{t} (1+\rho_\ell)} \left[1 - \frac{\nu^J}{\prod_{\ell=t+1}^{t+J} (1+\rho_\ell)} \right] \sum_{j=1}^{m} \delta_j\, u_{ijt} \quad .$$

The above program is essentially identical to the cost minimizing program and hence most of the solution techniques reviewed in Chapter 3 can be utilized.

The "perfect market" assumption is a very crucial assumption in all of the above development and it cannot be relaxed without altering the basic nature of the program. Similarly, neglecting the price elasticity has simplified the problem considerably. If price elasticity is incorporated into the model, then the program will have the demand curve function for electricity in the objective function and many of the variables cannot be eliminated and a generalized solution technique would be required.

CHAPTER 7

RISING COST OF CAPITAL CAPACITY PLANNING

7.1 Introduction

As mentioned in earlier chapters a common characteristic of many existing capacity expansion planning models is the use of a constant cost of capital. However, in practice, a firm faces a capital supply curve such that the more money it wants to borrow, the more it has to pay for it. This concern over lack of supply curve of capital in models of capacity expansion is voiced in [2] and [26]. For an electric utility, the specification of a capital supply curve gets added significance because of the large amounts of capital involved.

Let k_ℓ denote the capital cost (unannualized) for the equipment type ℓ. Also, let $(x_1, \ldots, x_N)$ be a decision vector which represents the capacities of various equipment types. Further, assume that α denotes a fixed discount rate and $f(x)$ denotes the fuel costs associated with decision x. With these assumptions a constant cost of capital, single period, capacity expansion planning problem is,

$$\begin{aligned} \text{Min} \quad & \alpha[k_1x_1 + \ldots + k_Nx_N] + f(x_1, \ldots, x_N) \\ \text{s.t.} \quad & x_1 + x_2 + \ldots + x_N = P \qquad (7.1) \\ & x \geqq 0 \end{aligned}$$

Here, P denotes the peak load. Note that the first term in the objective function can be interpreted as the rent on the capital employed and the second term $f(x_1,\ldots,x_N)$, as the fuel cost.

The following program is a generalization of (7.1) in the sense that it incorporates a capital supply curve:

$$\begin{aligned} \text{Min} \quad & i(C)C + f(x_1, \ldots, x_N) \\ \text{s.t.} \quad & x_1 + \ldots + x_N = P \qquad\qquad (7.2) \\ & k_1x_1 + \ldots + k_Nx_N = C \\ & x \geqq 0 \end{aligned}$$

Here, i(C) is the capital supply curve. A typical capital supply curve will be monotone increasing as illustrated in Fig. 7.1. Note that we have not assumed any special form for the fuel cost function $f(x)$.

7.2 Properties of the Optimal Solution to the Rising Cost of Capital Capacity Planning Problem

Let the solution to (7.1) for a given α be $x(\alpha)$. Also, let $k_1x_1(\alpha) + \ldots + k_Nx_N(\alpha)$ be denoted by $C(\alpha)$. Consider the following program:

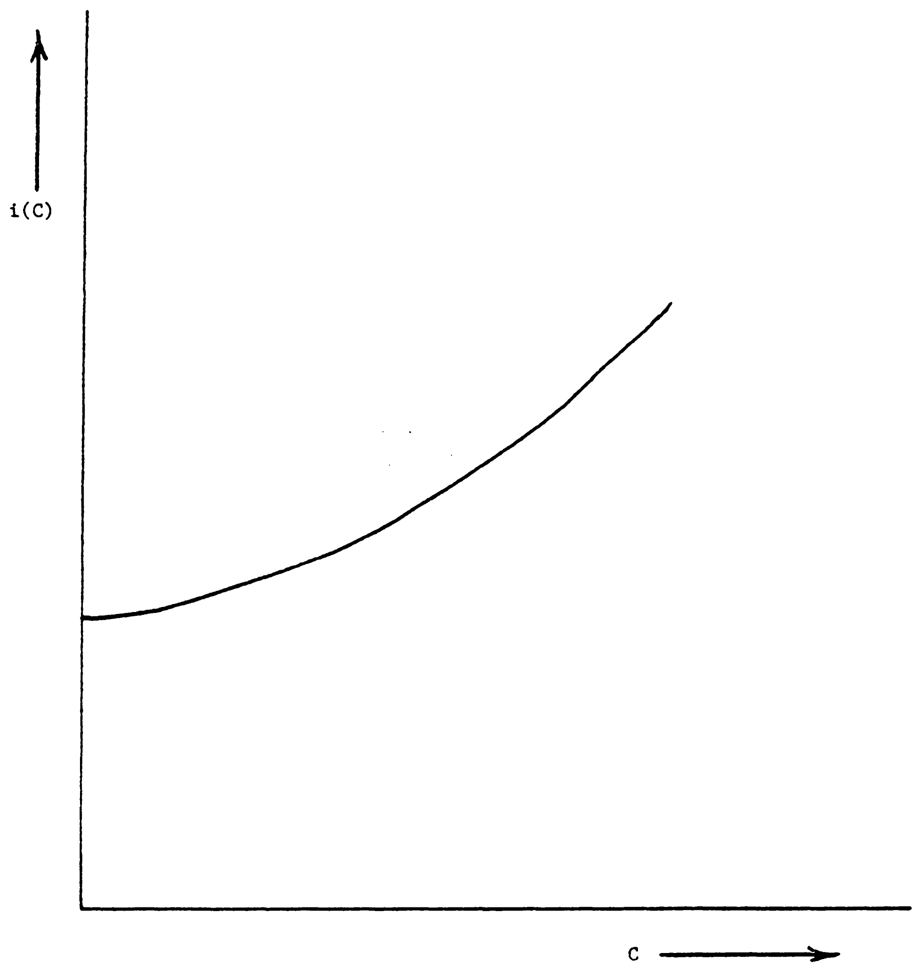

Figure 7.1. A Rising Cost of Capital Curve

$$\begin{array}{ll} \text{Min} & f(x) \\ \text{s.t.} & k_1x_1 + \ldots + k_Nx_N = C(\alpha) \\ & x_1 + \ldots + x_N = P \\ & x \geq 0 \end{array} \tag{7.3}$$

Note that (7.1) is closely-related to the Lagrangian dual of (7.3) and from Everett's Theorem [19], it follows that $x(\alpha)$ is also optimal to (7.3) and α is an optimal dual multiplier associated with the first constraint in (7.3). Also, note that the dual variable α for program (7.3) can be interpreted as the marginal savings in the fuel cost by increasing the capital expenditures by a small amount from $C(\alpha)$.

Let us also define a marginal cost of capital curve for a given $i(C)$ curve. The total cost for a given C is $i(C)C$. Differentiating the total cost with respect to C, one obtains the marginal cost of capital curve $u(C)$ as follows,

$u(C) = i(C) + i'(C)C$. (Here, $i(C)$ is assumed to be differentiable)

It follows from a simple economic argument that at an optimal capital expenditure level for program (7.2), marginal savings in fuel cost should equal the marginal cost of capital. A formal mathematical proof of the above observation is given in [45].

In Figure 7.2, the curves $C(\alpha)$, $i(C)$ and $u(C)$ are drawn and labeled marginal fuel saving, average cost of capital and marginal cost of capital, respectively. Notice that $i(C)$ and $u(C)$ are drawn with abscissa as the independent axis but $C(\alpha)$ has the vertical axis as the independent axis. As shown in Figure 7.2, the $C(\alpha)$ in general will not be a well defined function. We will analyze the shape of the $C(\alpha)$ curve in the next section.

Let us now contrast the optimal solutions to (7.1) and (7.2). In particular, suppose that (x^*, C^*) is an optimal solution to (7.2). Let $i^* = i(C^*)$. It might seem reasonable to expect that if one fixes $\alpha = i^*$ in (7.1) then x^* would also be optimal for (7.1). However, as shown in the following theorem, this is typically not the case.

Theorem 7.1

Let (x^*, C^*) be an optimal solution to (7.2) and $\bar{x}$ be an optimal solution to (7.1) with $\alpha = i(C^*)$. Then, for a strictly increasing $i(C)$ one has

$k_1\bar{x}_1 + \ldots + k_N\bar{x}_N \geq k_1x_1^* + \ldots + k_Nx_N^* = C^*$, i.e., the solution $\bar{x}$ is at least as capital intensive as x^*.

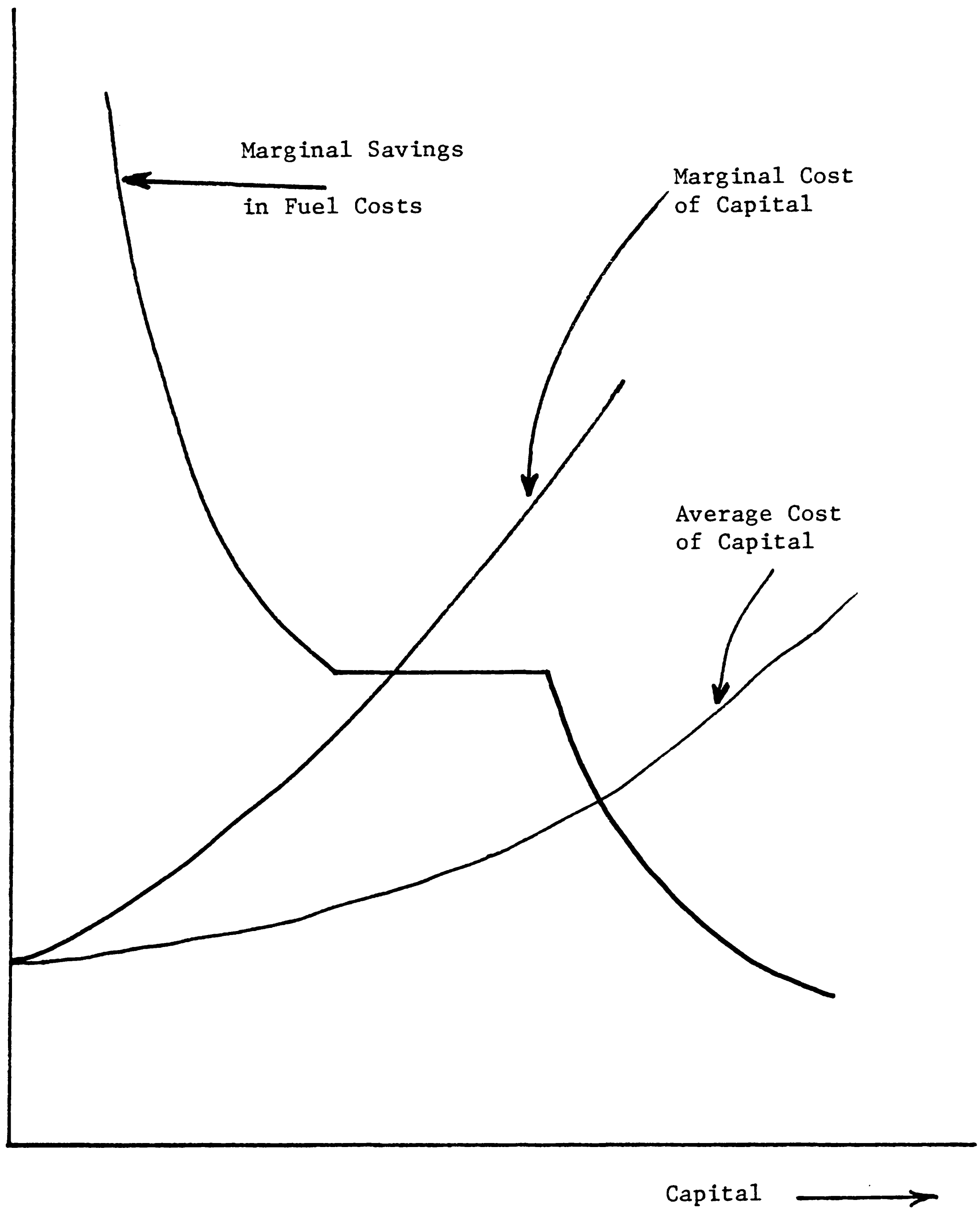

Figure 7.2. The Solution to the Rising Cost of Capital Capacity Planning

Proof:

On the contrary assume,

$$k_1\bar{x}_1 + k_2\bar{x}_2 + \dots + k_N\bar{x}_N < k_1x_1^* + k_x x_2^* + \dots + k_N x_N^* .$$

Let $\bar{C} = k_1\bar{x}_1 + \dots + k_N\bar{x}_N$ and observe that x^* is feasible to program (7.1). By the optimality of $\bar{x}$ to (7.1), it follows that,

$$i(C^*)\bar{C} + f(\bar{x}) \leqq i(C^*)C^* + f(x^*) .$$

Next, consider any point on the line segment connecting the points $(\bar{x},\bar{C})$ and (x^*,C^*). Let the point be denoted by $(\hat{x},\hat{C})$, where $\bar{C} < \hat{C} < C^*$. Since, $(\bar{x},\bar{C})$ is a global minimum of $i(C^*)C + f(x)$ restricted by the constraint $x_1 + \dots + x_N = P$, it follows that,

$$i(C^*)\hat{C} + f(\hat{x}) \leqq i(C^*)C^* + f(x^*) \tag{7.4}$$

Moreover, since $\bar{C} \geqq 0$, $\hat{C} > 0$. For a strictly increasing $i(C)$, one has,

$$i(\hat{C}) < i(C^*).$$

Now, from (7.4) it follows that,

$$i(\hat{C})\hat{C} + f(\hat{x}) < i(C^*)C^* + f(x^*).$$

Since $(\hat{x},\hat{C})$ is feasible to (7.2), the above inequality is a contradiction to the optimality of (x^*,C^*) to (7.2).

In general, $\bar{C} \geqq C^*$ but typically $\bar{C} > C^*$. This capital bias is shown in Figure 7.3. This capital bias might be the root cause for the fact that many capacity planning models seem to generate overly capital intensive solutions.

7.3 Solution Strategy

The solution strategy we describe in this section is graphical in nature. In the suggested solution strategy, one constructs

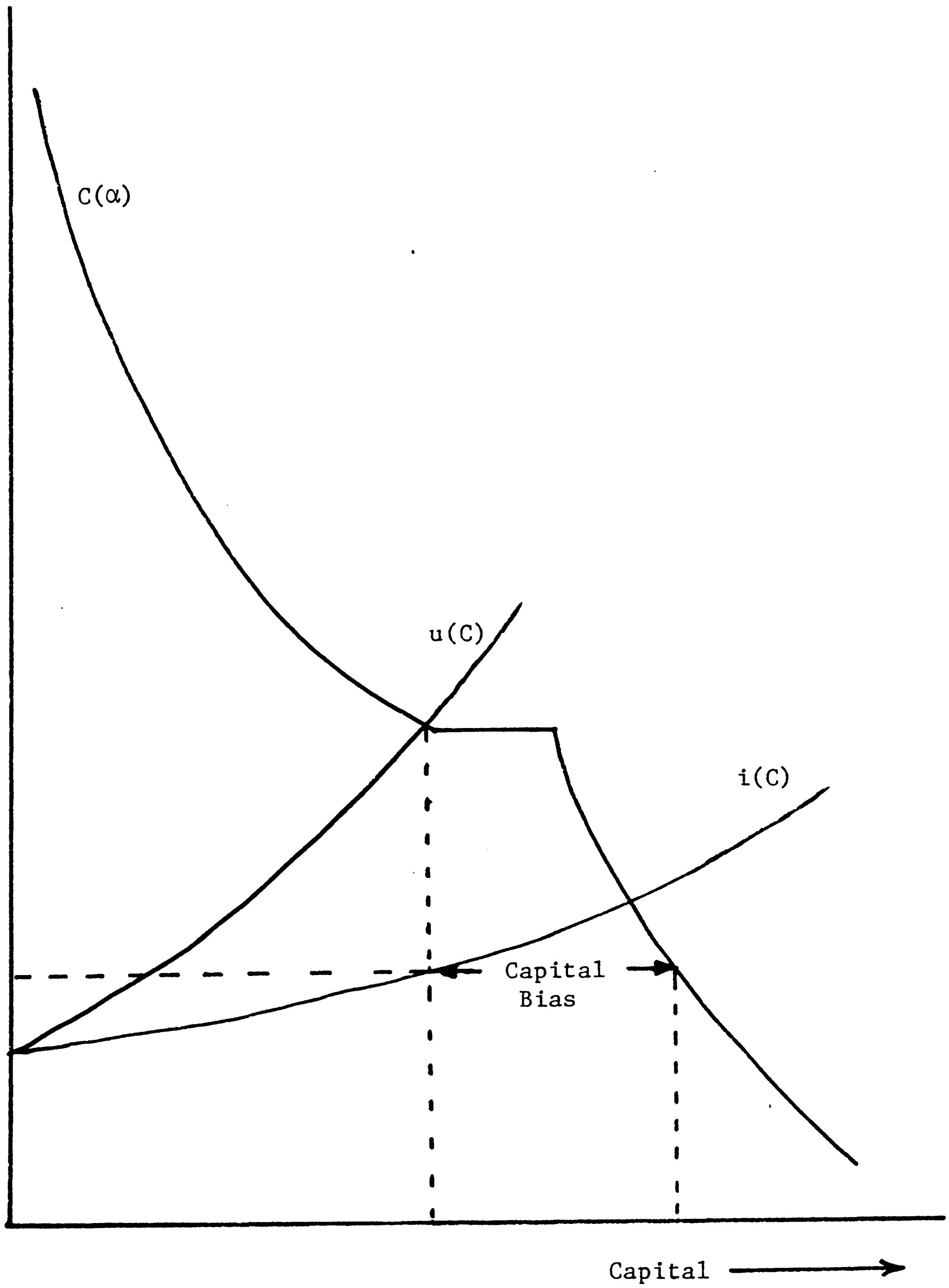

Figure 7.3. Capital Bias

the $C(\alpha)$ curve and $u(C)$ curves to obtain an optimum (u^*, C^*). From the development in the earlier section, it is clear that if one uses u^* as the cost of capital in a constant cost of capital capacity planning problem, one can produce the optimal solution x^*.

The above strategy for finding x^* is a two stage graphical procedure. In the first stage, one finds the optimal u^*. Then, this u^* can be used to construct a breakeven chart and the solution x^* can be obtained as in Chapter 3. The above strategy depends on one's ability to construct the $C(\alpha)$ curve. Now, we prove a theorem which addresses this problem.

Theorem 7.2

Consider a constant cost of capital capacity planning problem as in (7.1). Then,

(i) if the load curve $h(.)$ is continuous, then $C(\alpha)$ is a continuous function of α;

(ii) if the load curve $h(.)$ is linear, then $C(\alpha)$ is piecewise linear;

(iii) if there is a baseload portion of the load curve (for example, trapezoidal), then $C(\alpha)$ will have a finite number of discontinuities.

Proof:

Let the fuel cost for equipment type ℓ be g_ℓ. Also, without loss of generality, assume,

$$k_\ell > k_{\ell+1} \quad (\text{for all } \ell \in [1,N-1]), \text{ and}$$

$$g_\ell < g_{\ell+1} \quad (\text{for all } \ell \in [1,N-1]).$$

For a given α, the solution to (7.1) can be associated with a set of breakeven points [55]. Let us denote the set as σ.

$$\sigma = \{\sigma_1, \ldots., \sigma_{N-1}\},$$

where

$$\sigma_\ell = \frac{\alpha\,[k_\ell - k_{\ell+1}]}{[g_{\ell+1} - g_\ell]}$$

Next, consider (N+1) numbers specified by

$$b_\ell = \frac{k_\ell - k_{\ell+1}}{g_{\ell+1} - g_\ell},$$

$$b_N = 0,$$

$$b_0 = \infty.$$

Note that if $b_\ell < b_{\ell+1}$ for some ℓ then $(\ell+1)$st equipment type is dominated for all values of α. (As mentioned in Chapter 3, a dominated equipment type is one for which there is a better equipment type to use at all utilization levels.)

Thus, if $b_\ell < b_{\ell+1}$ for some ℓ, then one can remove $(\ell+1)$st equipment type from the problem and renumber the remaining equipment types. Since the total number of equipment types (N) is finite, repeating this process of removing dominated equipment types and renumbering the remaining, one can obtain a sequence $\{b_0, b_1, \ldots, b_{N_U}\}$ such that $b_\ell \geq b_{\ell+1}$ for all $\ell \in [0, N_U-1]$. Here, N_U stands for number of nondominated equipment types.

Now, it is straightforward to show that $C(\alpha)$ for a given α, is given by,

$$C(\alpha) = \sum_{j=1}^{N_U} k_j[h\{\min(1,\alpha b_{j-1})\} - h\{\min(1,\alpha b_j)\}] \qquad (7.5)$$

(i) Note that $\min(1,\alpha b_j)$ is a continuous function of α. Hence, for a continuous $h(.)$ the continuity of $C(\alpha)$ follows from (7.5).

(ii) Also, $\min(1,\alpha b_j)$ is a piecewise linear function of α, and for a linear $h(.)$, the piecewise linearity of $C(\alpha)$ follows. $C(\alpha)$ for a linear load curve is shown in Figure 7.4.

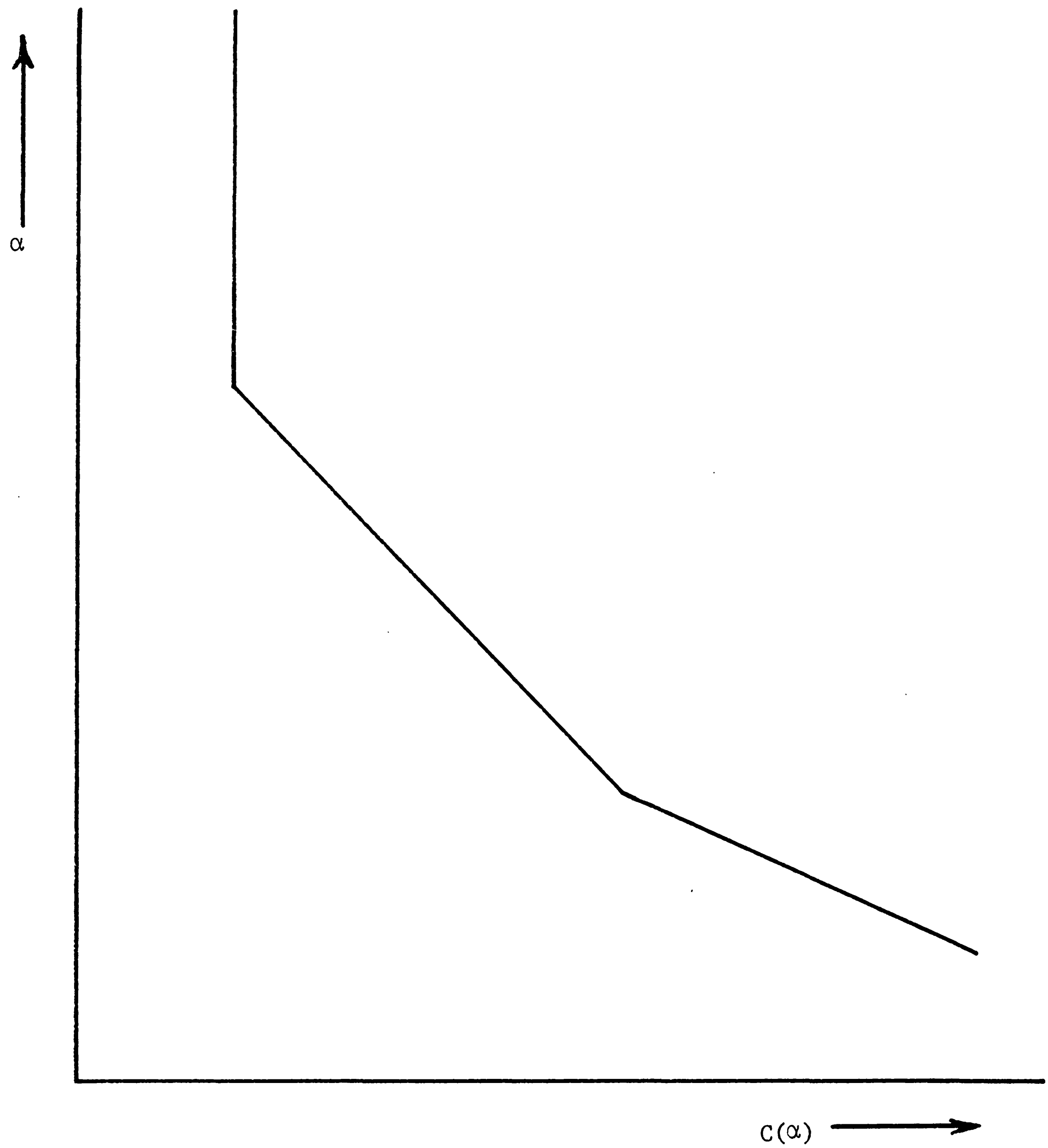

Figure 7.4. C(α) for a Linear Load Curve

(iii) Typically, there will be certain values of α for which some breakeven point in the breakeven chart is exactly equal to 1.0. When h(.) has a baseload portion, then such a situation will give rise to alternative optima with different values of capital outlays. Thus, $C(\alpha)$ will be discontinuous at these values of α. $C(\alpha)$ for a trapezoidal load curve is shown in Figure 7.5.

Thus using Equation (7.5) one can construct the $C(\alpha)$ curve and find u^* from the intersection of $C(\alpha)$ and $u(C)$. This u^* can be used in a simple breakeven chart technique to obtain the optimal capacities of different equipment types.

Next, we consider an example to illustrate the above graphical technique. Let us consider a capacity planning problem with 4 equipment types under consideration. Let the capital and fuel cost data for the various equipment types be as shown in Table 7.1.

Let the load curve be linear with peak P = 500 kW. Also, let the firm be faced with a rising cost of capital curve given by,

$$i(C) = .1 + 5 \times 10^{-7} C$$

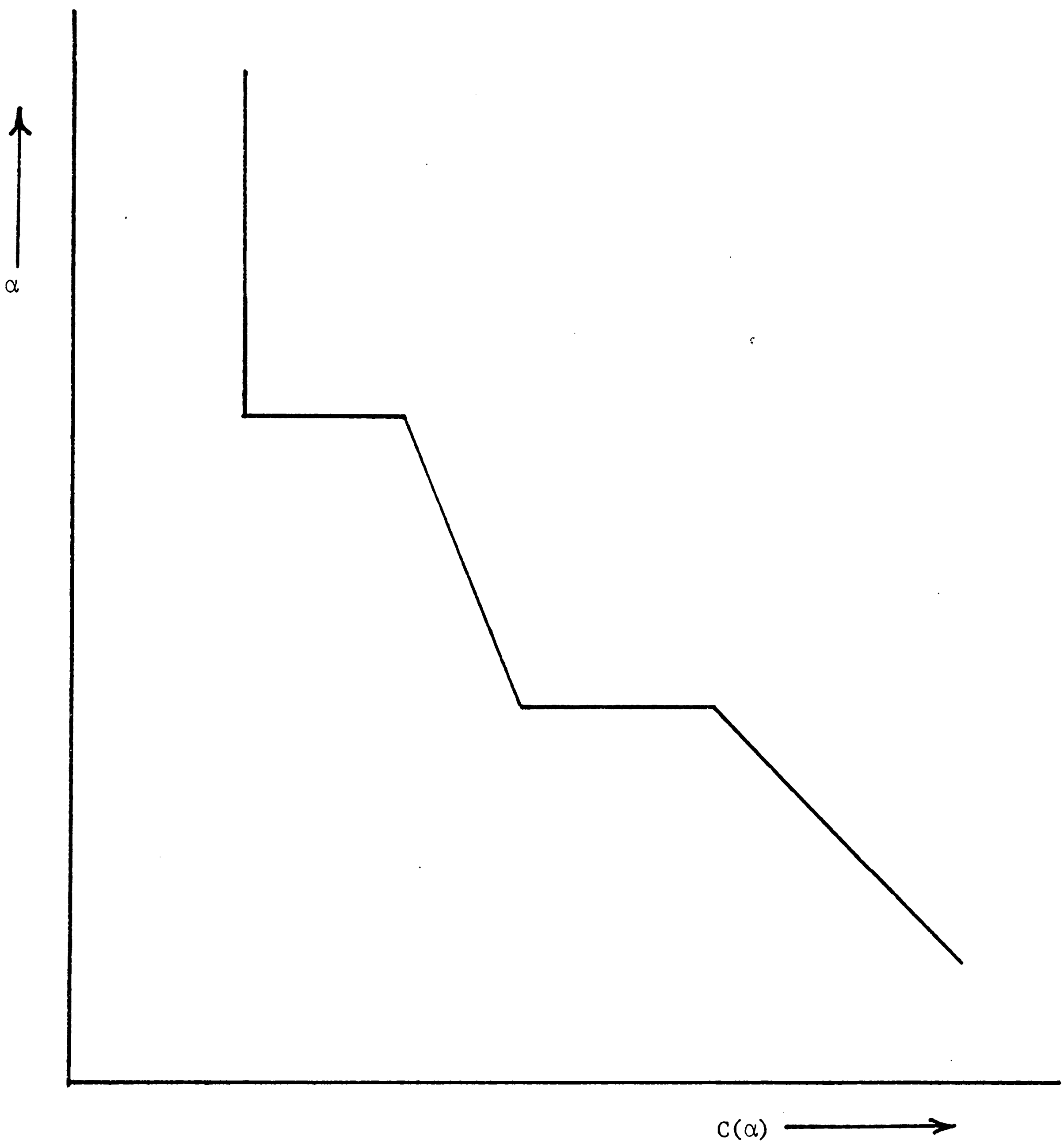

Figure 7.5. C(α) for a Trapezoidal Load Curve

Table 7.1

Cost Data for Different Equipment Types

Equipment	Capital Cost ($/kW)	Fuel Cost ($/kW yr)
1	1500	100
2	1300	200
3	1000	300
4	900	400

With the above data one has,

$$b_0 = \infty$$

$$b_1 = \frac{1500-1300}{200-100} = 2.0$$

$$b_2 = \frac{1300-1000}{300-200} = 3.0, \qquad \text{(dominated)}$$

$$b_3 = \frac{1000-900}{400-300} = 1.0,$$

$$b_4 = 0.0.$$

Since $b_1 < b_2$, equipment type 2 is dominated. Renumbering one can obtain,

$$b_0 = \infty$$

$$b_1 = 2.5$$

$$b_2 = 1.0$$

$$b3 = 0.0$$

From equation (7.5) one can obtain,

for $\alpha > 1.0$, $\qquad C(\alpha) = 4.5 \times 10^5$;

for $\alpha \in [.4, 1.0]$, $\qquad C(\alpha) = 5 \times 10^5 - .5 \times 10^5 \alpha$;

for $\alpha < .4$, $\qquad C(\alpha) = 7.5 \times 10^5 - 6.75 \times 10^5 \alpha$.

Also, $u(C) = .1 + 10^{-6}C$. The graphs of $C(\alpha)$ and $u(C)$ are given in Figure 7.6 where one obtains $u^* = .5713$.

For the above value of u^*, the relevant breakeven points are .5713 and 1.42825. Thus, the optimal solution is,

$$x_4^* = .5713(500) = 285.65 \text{ kW},$$

$$x_3^* = 500 - 285.65 = 214.35 \text{ kW},$$

$$x_2^* = 0,$$

$$x_1^* = 0.$$

The capital investment in this solution is 4.713×10^5 dollars.

To observe the capital bias of Theorem 7.1, note that the average cost of capital at an investment level of 4.713×10^5 is .3357. If one solves a single period, constant cost of capital capacity planning problem with the cost of capital equal to .3357, one obtains the following solution:

$$\bar{x}_4 = .3357(500) = 167.85 \text{ kW},$$

$$\bar{x}_3 = .83925(500) - 167.85 = 251.775 \text{ kW},$$

$$\bar{x}_2 = 0,$$

$$\bar{x}_1 = 80.375 \text{ kW}.$$

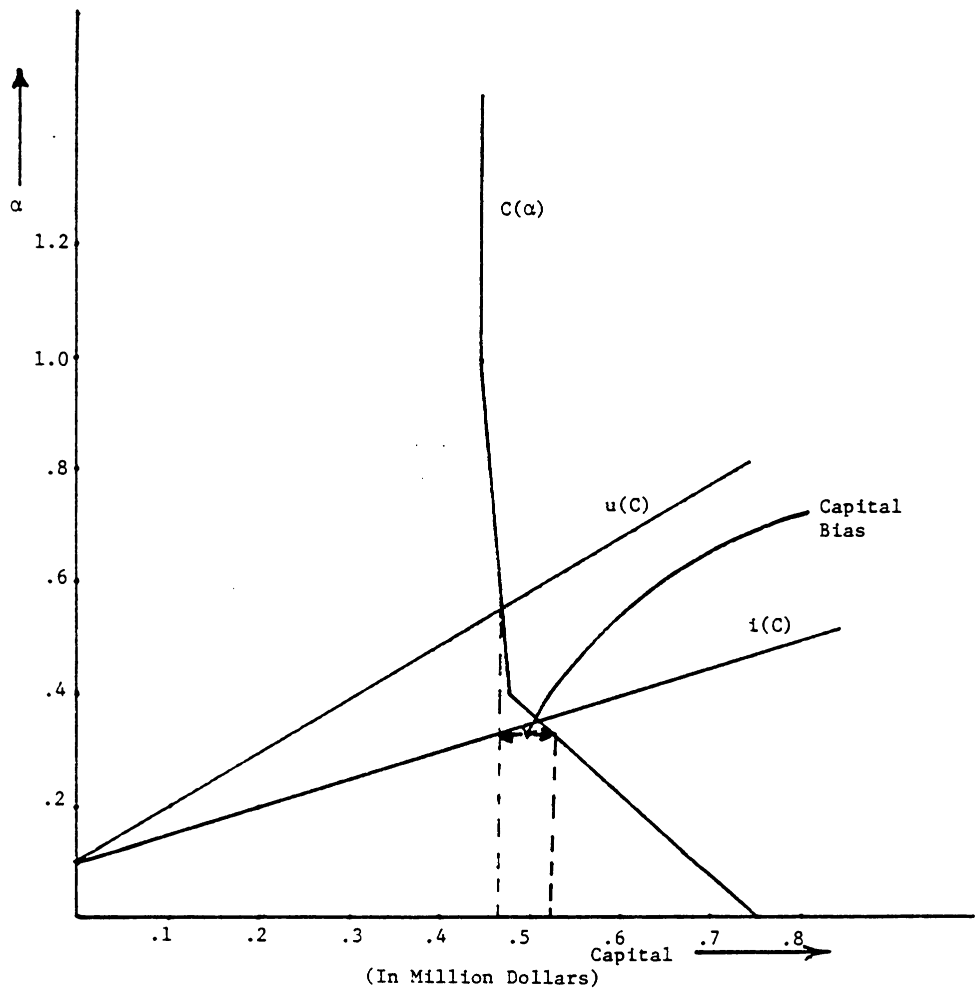

Figure 7.6. Capital Bias for the Numerical Example

The total capital outlays at this solution is 5.234×10^5 dollars. The difference of 5.21×10^4 dollars (or 11.05%) between the solution obtained by constant cost of capital and rising cost of capital models represents the capital bias. This capital bias is shown in Fig. 7.6.

CHAPTER 8

ESTIMATION OF THE CAPITAL SUPPLY CURVE FOR AN ELECTRIC UTILITY

8.1 Introduction

In this chapter, we develop an approach to estimate the capital supply curve for an electric utility. The capital supply curve refers to i(C) curve of the last chapter. The fundamental assumption behind a capital supply curve is that capital is a scarce resource and greater quantities can only be acquired at greater cost. The approach being presented is to estimate the capital supply curve for a single electric utility. When the rising cost of capital model is used for regional capacity planning, one needs a supply curve of capital for the whole region. In such a situation, our strategy is to treat the whole region as a single utility. The above aggregation, though consistent with other strategies and models for regional capacity expansion planning, ignores the interfirm differences within a region.

Table 8.1 shows the differences in the cost of debt and equity capitals for various classes of utilities. All of these differences are not attributable to capital outlays alone. The other factors which affect the cost of capital for an electric utility are its existing capital structure, competition from other energy sources and regulatory climate, etc.

Table 8.1

Moody's Average Yields on Utility Bonds and Stocks

	Bonds				Common Stock					
	Rating				High Quality		Good Quality		Medium Quality	
	Aaa	Aa	A	Baa	Yield	E/P Ratio	Yield	E/P Ratio	Yield	E/P Ratio
Dec., 1980	13.18%	13.91%	14.14%	15.20%	11.49%	15.65%	12.36%	16.86%	13.27%	17.01%
Sept., 1980	12.91	13.49	13.74	14.58	11.37	15.46	11.83	16.01	12.77	15.71
June, 1980	11.30	11.84	12.22	12.81	10.24	13.41	10.65	14.36	11.52	13.22
March, 1980	13.35	14.57	14.96	15.41	12.15	15.50	12.52	18.27	13.93	19.11

Source: Edison Electric Statistical Yearbook, 1980

There are at least two different approaches that one may take in attempting to construct the capital supply curve for an electric utility. One strategy is to statistically correlate the cost of capital for various electric utility firms with the capital intensities of their capacity expansion plans. Such a strategy, though appealing, overlooks the interfirm differences other than capital outlays.

A second strategy is to assess the impact of different capital outlays on various financial parameters of the firm. These financial parameters can, in turn, be statistically related to the cost of capital for a firm. Thus, this strategy consists of a two stage model. The first stage of the model can be deterministic because the various financial parameters are related to capital outlays through accounting relationships. The second stage is to assess the impact of changes in various financial parameters on the cost of capital. This can be achieved by statistical means, for example, regression analysis, discriminant analysis, etc.

We will use the second strategy to estimate the capital supply curve. Fortunately, the first stage accounting model for electric utilities is available in the form of National Utility Financial Statement (NUFS) model [13]. NUFS is developed by ICF, Inc. The objective of the NUFS model is to analyze the impact of various capacity expansion decisions on the financial outlook of a firm. In particular, NUFS constructs a sequence of yearly income statements and balance sheets for any given capacity expansion plan. In this manner, one can determine how the capacity expansion decision will affect the various parameters like interest coverage, construction work in progress (CWIP).

The NUFS model requires a number of inputs, including a capacity expansion plan for each period in the planning horizon (typically 15 to 20 years). NUFS also needs base year data about the utility's generation and capacities for different plant types. NUFS can be run for an individual utility or an aggregate set of utilities at a regional or national level. If the model is run at the regional level, the above data is needed both for investor-owned and public utilities. Further, NUFS needs user-supplied assumptions about AFUDC, CWIP, flow-through percentage, capital structure, etc. The two most important inputs from our point of view are the assumptions about the cost of debt and equity for each year in the forecast period. However, since we wish to use NUFS to determine the cost of capital curve, we cannot use the NUFS model in its present form.

In the next section, we describe a method of adapting NUFS so that the cost of debt and equity capital is determined endogeneously.

8.2 Extended NUFS Model

The extended NUFS model is based on a process of equilibrium. Preliminary cost of capital assumptions, supplied by the user, are adjusted to achieve a situation in which the user supplied assumptions are consistent with the resulting financial statements.

Let us address the meaning of consistency between an assumed cost of capital and financial statements. Let us suppose the planning horizon is T periods long. Suppose that one could construct an empirical relationship between equity cost, i_e, and debt cost, i_d, as a function of r parameters from the financial statements of the firm; say $p_1, p_2, \ldots, p_r$. In particular, let us postulate that

$$i_e = f_1(p_1, p_2, \ldots, p_r) \tag{8.1}$$

and

$$i_d = f_2(p_1, p_2, \ldots, p_r). \tag{8.2}$$

By consistency we mean that the assumptions about i_e and i_d should be the same as (or close to) those implied by the financial parameters $p_1, p_2, \ldots, p_r$.

Specifically, suppose we "guess" at capital costs of $\bar{i}_e$ and $\bar{i}_d$. These estimates are then used in NUFS, along with many other assumptions concerning expansion plans, operating costs and regulatory environment. What is generated is a balance sheet and income statement that would be associated with the particular expansion plan. These financial documents give rise to a number of financial and operating parameters which, when substituted into (8.1) and (8.2) result in implied costs of capital $\hat{i}_e$ and $\hat{i}_d$. If $(\hat{i}_e, \hat{i}_d)$ and

$(\bar{i}_e, \bar{i}_d)$ are reasonably close, then there is consistency between assumptions and results. However, since NUFS is a multiperiod model, the aforementioned process needs to be modified since the scalar quantities, i_e and i_d, would now be vector-valued, i.e., (8.1) and (8.2) need to be time dependent. For the multiperiod case, analogous to (8.1) and (8.2), one has,

$$i_e^t = f_1(p_1^t, p_2^t, \ldots., p_r^t) \tag{8.3}$$

and

$$i_d^t = f_2(p_1^t, p_2^t, \ldots., p_r^t). \tag{8.4}$$

Thus, the multiperiod consistence will be achieved when the cost of capital implied by the financial parameters is the same as the one assumed for each of the periods in the horizon. If this situation is achieved, the process is in "equilibrium." Of course, such a situation is a bit much to hope for.

A more realistic approach has been developed in this research, and has resulted in an "extended" NUFS model (The term extended applies to the fact that the costs of debt and equity capital are determined endogenously). In this approach, one still begins with estimates $\bar{i}_e$ and $\bar{i}_d$ and these are used for each period in the T period planning horizon. Then the sequences $\{i_d^t\}$ and $\{i_e^t\}$ are calculated according to (8.3) and (8.4) using the parameters from the NUFS output, $(p_1^t, p_2^t, \ldots, p_r^t)$. Next, one determines a single scalar, $\hat{i}_d$ and $\hat{i}_e$ as follows:

$$1 + \hat{i}_e = [(1+i_e^1)(1+i_e^2) \ldots (1+i_e^T)]^{1/T} \tag{8.5}$$

and,

$$1 + \hat{i}_d = [(1+i_d^1)(1+i_d^2) \ldots (1+i_d^T)]^{1/T} . \tag{8.6}$$

The above surrogate $\hat{i}_e(\hat{i}_d)$ is roughly equivalent to $\{i_e^t\}$ $(\{i_d^t\})$ in the sense that a dollar at the end of the horizon has the same value at time zero under discounting based on $\hat{i}_e(\hat{i}_d)$ and $\{i_e^t\}$ $(\{i_d^t\})$.

For the specification of the function f_1, the extended NUFS model uses statistical relationships between market to book ratio and financial parameters. The model user has a choice to use either Roseman [13] regression or Trout [54] regression. The two regressions are now described.

Roseman explains the price to book ratio for electric utility stock by the rate of return on common equity, accounting method used (normalization vs. flowthrough), AFUDC as a percentage of net income and ratio of dividends to cash flow variables using 1973-74 data. The actual regression equation obtained is:

$$P/B = .222751 + .0255174(x_1) + .000982544(x_2)$$
$$+ .00232095(x_3) - .134129(x_4) - .00096935(x_5)$$
$$- .00268022(x_6) + .554664(x_7)$$

where

P/B = price to book ratio

x_1 = return on common equity, 1974

x_2 = square of the rate of return on common equity, 1973

x_3 = square of the rate of return on common equity, value line estimate for 1975

x_4 = accounting method: 1 if flowthrough
0 if not flowthrough

x_5 = oil as a percent of all fuels used in generation, 1974

x_6 = AFUDC as a percent of net income for common, 1974

x_7 = ratio of dividends to cash flow, 1974.

Trout estimated a regression equation to explain market to book ratio by return on equity, leverage, payout ratio, regulatory climate, cost of power sold, AFUDC as a percent of net income and deferred taxes to total cash flow variables. The regression equation estimated is:

$$\hat{P/B} = .0202\ \hat{ROE} + .0549\ ROAE - .0052\ LEV + .0087\ PAY + .0221\ PCTEL - .0058\ SALC + .0634\ REGP - .0591\ REGN - .0014\ AFCNI + .0013\ DTCF - .2380$$

where,

$\hat{ROE}$	= Expected return on equity for the next year
ROAE	= Return on average equity for the past year
LEV	= Ratio of debt to total capital
PAY	= Ratio of common dividends paid to the income available to common equityholders.
PCTEL	= Ratio of electric revenues to total revenues
SALC	= Cost of power sold (mills/kWh)
AFCNI	= AFUDC as a percent of net income
DTCF	= Ratio of deferred taxes to total cashflows
REGP	= 1 if the firm is in a state where the regulatory attitude is above average 0 if the firm is not in a state where the regulatory attitude is above average
REGN	= 1 if the firm is in a state where the regulatory attitude is below average 0 if the firm is not in a state where the regulatory attitude is below average.

The regression equation fits the data with an R^2=.79.

For the specification of f_2, a regression equation estimated by Edelman [14] to replicate electric utility bond ratings by the financial ratios is used in the extended NUFS model. The Edelman [14] regression is described in Section 2.3.

The model starts with user-supplied estimates of cost of equity and cost of debt capital. These estimates are used to forecast balance sheets and income statements during the planning horizon. From these forecasted balance sheets and income statements the bond rating and price to book ratio are estimated. From bond rating a yield on bonds is interpolated and from price to book ratio and return to book value an estimate for yield on market value if obtained. If the estimates of yield on debt and equity are within the user-supplied range from the initial starting solution, the process stops. On the other hand, if the estimates of the yields are not within the specified tolerance from the initial guess, a convex combination of initial guess and estimate obtained from financial statements is used as the next guess. A judicious choice of convex combination is essential for the convergence of the procedure. Typically, a user might have to experiment with several different convex combinations to achieve an optimum one for his application and data. Is the initial guess is weighted very heavily, the procedure might take very long to obtain the equilibrium point. On the other hand, if the initial guess is not weighted appropriately, the procedure might diverge. The weight on the initial guess is user-supplied. A schematic description of the above procedure is presented in the flow chart in Figure 8.1.

8.3 Using Extended NUFS Model to Estimate the Capital Supply Curve

The extended NUFS model, like NUFS, needs a capacity expansion plan as input. Thus, for a given capacity expansion decision, the extended NUFS model can be used to obtain the equilibrium cost of capital. Hence, by using various capacity expansion plans of different capital intensities, one can generate as many points on the capital supply curve, i(C), as desired.

The above strategy has been used to estimate the capital supply curve, i(C), for DOE Region 1. DOE Region 1 consists of the states Maine, Vermont, New Hampshire, Massachusetts, Connecticut and Rhode Island. The analysis was made with the currently existing treatment of CWIP, AFUDC and other regulatory parameters for the region. Since the public utilities' common stock (the government investment) is not traded in the market, no equilibration was done on equity for public utilities. Instead, the cost of public utility equity was kept fixed at 14.86% which is the prevailing assumption in the region.

Table 8.2 shows the results of the analysis with the Roseman regression equation and Table 8.3 shows the results of the analysis with the Trout regression equation. Each row in Tables 8.2 and

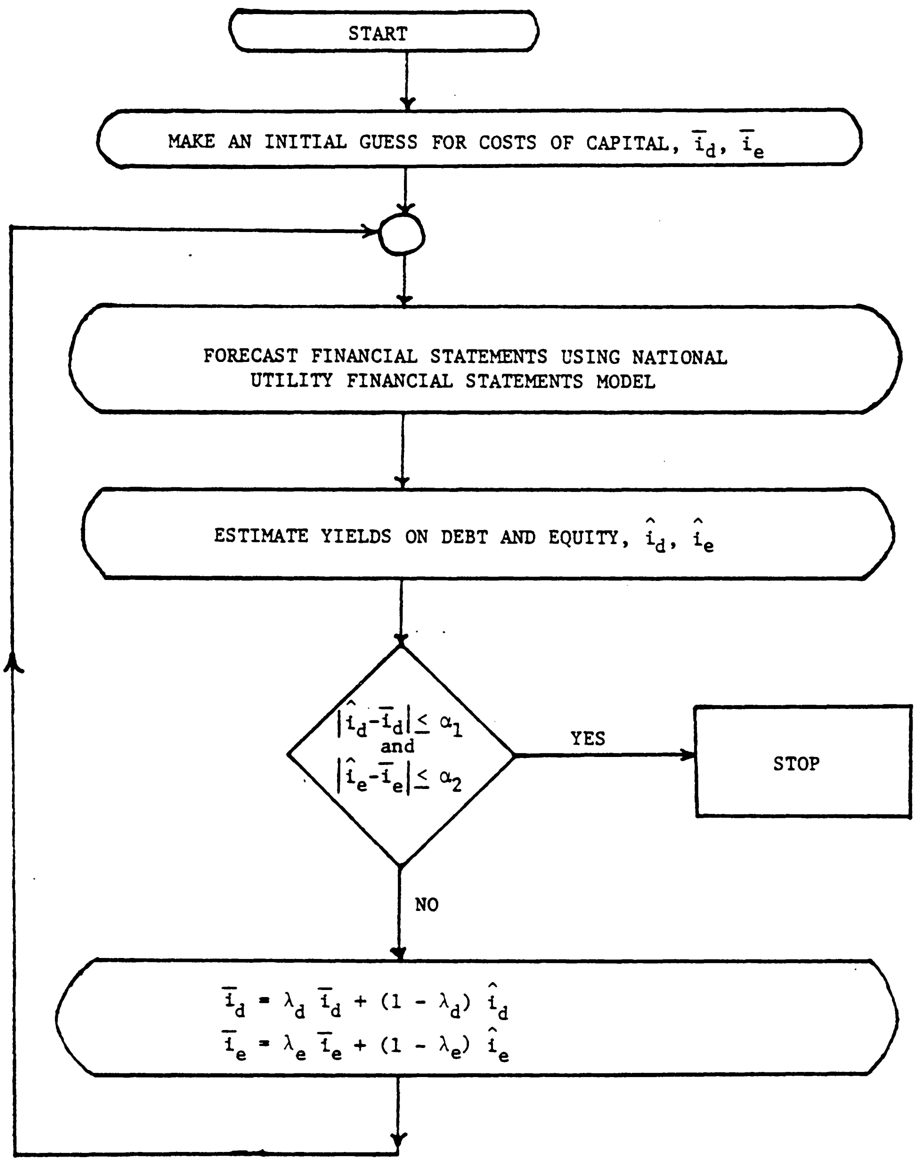

Figure 8.1. Flowchart for the Extended NUFS Algorithm

Table 8.2

i(C) Using Roseman Regression Equation for Region 1

Capital Cost ($/kW)	Private Utilities Capital Outlays (10^6 dollars)	Private Utilities Cost of Debt (%)	Private Utilities Cost of Equity (%)	Public Utilities Capital Outlays (10^6 dollars)	Public Utilities Cost of Debt (%)	Public Utilities Cost of Equity (%)
49.621	122.43	8.74	12.71	0.79	8.94	14.86
176.067	416.64	8.74	12.16	2.68	8.99	14.86
220.850	556.89	8.75	12.34	3.58	9.01	14.86
442.890	1220.11	8.76	12.65	7.85	9.08	14.86
516.705	1345.86	8.74	12.45	8.66	9.08	14.86
551.670	1436.94	8.74	12.45	9.25	9.08	14.86
927.627	2817.27	8.76	12.87	18.13	9.15	14.86
1243.200	3808.53	8.78	12.97	24.51	9.17	14.86

Table 8.3

i(C) Using Trout Regression Equation for Region 1

Capital Cost ($/kW)	Private Utilities: Capital Outlays (10^6 dollars)	Private Utilities: Cost of Debt	Private Utilities: Cost of Equity	Public Utilities: Capital Outlays (10^6 dollars)	Public Utilities: Cost of Debt	Public Utilities: Cost of Equity
49.621	122.43	8.72	13.49	0.79	8.94	14.86
176.067	416.64	8.71	13.59	2.68	8.99	14.86
220.850	556.89	8.72	13.76	3.58	9.01	14.86
442.890	1220.11	8.72	14.53	7.85	9.08	14.86
516.705	1345.86	8.69	14.30	8.66	9.08	14.86
551.670	1436.94	8.69	14.35	9.25	9.08	14.86
927.627	2817.27	8.69	15.33	18.13	9.15	14.86
1243.200	3808.53	8.69	15.93	24.51	9.17	14.86

8.3 corresponds to a capacity expansion plan for a particular capital intensity. In particular, each row in Tables 8.2 and 8.2 corresponds to a capacity expansion plan in which all the expansion needs of the region are met by expanding one single equipment type. For example, the first row corresponds to the capacity expansion plan when geothermal technology is used to meet the future expansion needs and the last row corresponds to the capacity expansion plan when nuclear plant type is used to meet the future expansion needs.

As depicted by the data in Tables 8.2 and 8.3, the nature of the cost of capital curve is, in general, rising. For obtaining the capital supply curve, i(C), to be used in the model of the last chapter, we will have to calculate the weighted average cost capital from the data of Tables 8.2 and 8.3. Further, since the cost of equity capital obtained in Tables 8.2 and 8.3 is the after-tax cost of capital, one has to calculate the before-tax cost of equity capital to make it compatible with debt cost of capital. The weighted average before tax cost of capitals for the data in Tables 8.2 and 8.3 are calculated and are shown in Table 8.4. A sample calculation of the weighted average before-tax cost of capital for the last row in Table 8.2 is shown below:

For Private Utilities:

After-tax cost of equity capital = 12.97%

Tax rate = 46%

Before-tax cost of equity capital $= \dfrac{12.97}{(1-.46)}$

$= 24.02\%$

Table 8.4

Before-Tax Cost of Capital for Region 1

Capital Outlays (10^6 dollars)	Roseman Regression	Trout Regression
	Before Tax Cost of Capital (%)	Before Tax Cost of Capital (%)
123.22	14.30	14.81
419.32	13.93	14.88
560.47	14.05	15.00
1227.96	14.27	15.38
1354.52	14.12	15.35
1446.19	14.12	15.38
2835.40	14.42	16.04
3833.04	14.50	16.45

Before-tax cost of debt	= 8.78 %
Before-tax cost of preferred stock	= 9.78 %

(assumed to be 1% more than cost of debt)

Percentage of debt in capital structure	= 51.24%
Percentage of preferred stock in capital structure	= 11.92%

Weighted average before-tax cost of capital

= 8.78 x .5124 + 9.78 x .1192 + 24.02 x .3684

= 14.51%

For Public Utilities:

After tax cost of equity capital	= 14.86 %
Tax rate	= 0%
Before-tax cost of equity capital	= 14.86 %
Before-tax cost of debt	= 9.17 %
Percentage of debt in capital structure	= 40.15%

Weighted average cost of capital

= 9.17 x .4015 + 14.86 x .5985

= 12.58%

Percentage of public utilities in the region	= .639%

Overall weighted average before tax cost of capital

= 14.51 x .99361 + 12.58 x .00639

= 14.50%

The weighted average before tax cost of capital data in Table 8.4 are plotted in Figure 8.2. As shown in Figure 8.2, the cost of capital curve obtained by the Roseman regression equation lies below the one obtained by the Trout regression. This might be attributable to different data from which the two regression equations were estimated. The Roseman regression is based on 1973-74 data. Also the Trout regression was obtained from 1977-78 data. The interest rates in the U.S. economy were relatively lower in 1973-74 than in 1977-78. This might be the reason for obtaining the i(C) based on the Roseman regression lower than the i(C) based on the Trout regression.

To analyze the sensitivity of the i(C) curve to various regulatory parameters, the prevailing regulatory parameters were changed one at a time. In particular, the changes in regulatory lag, percent CWIP allowed in the rate base, accounting method (flowthrough vs. normalization) and AFUDC rate were analyzed in terms of their effects on the equilibrium cost of capital for the most capital intensive and the least capital intensive capacity expansion plans. The results of the runs are summarized in Table 8.5. The first column in Table 8.5 shows the regulatory parameter being changed and its changed value. Columns 2 and 3 show the equilibrium, weighted average, before-tax cost of capital with the Roseman regression for the most capital intensive and the least capital intensive capacity expansion plan, respectively. Columns 3 and 4 show the same results for the Trout regression equation.

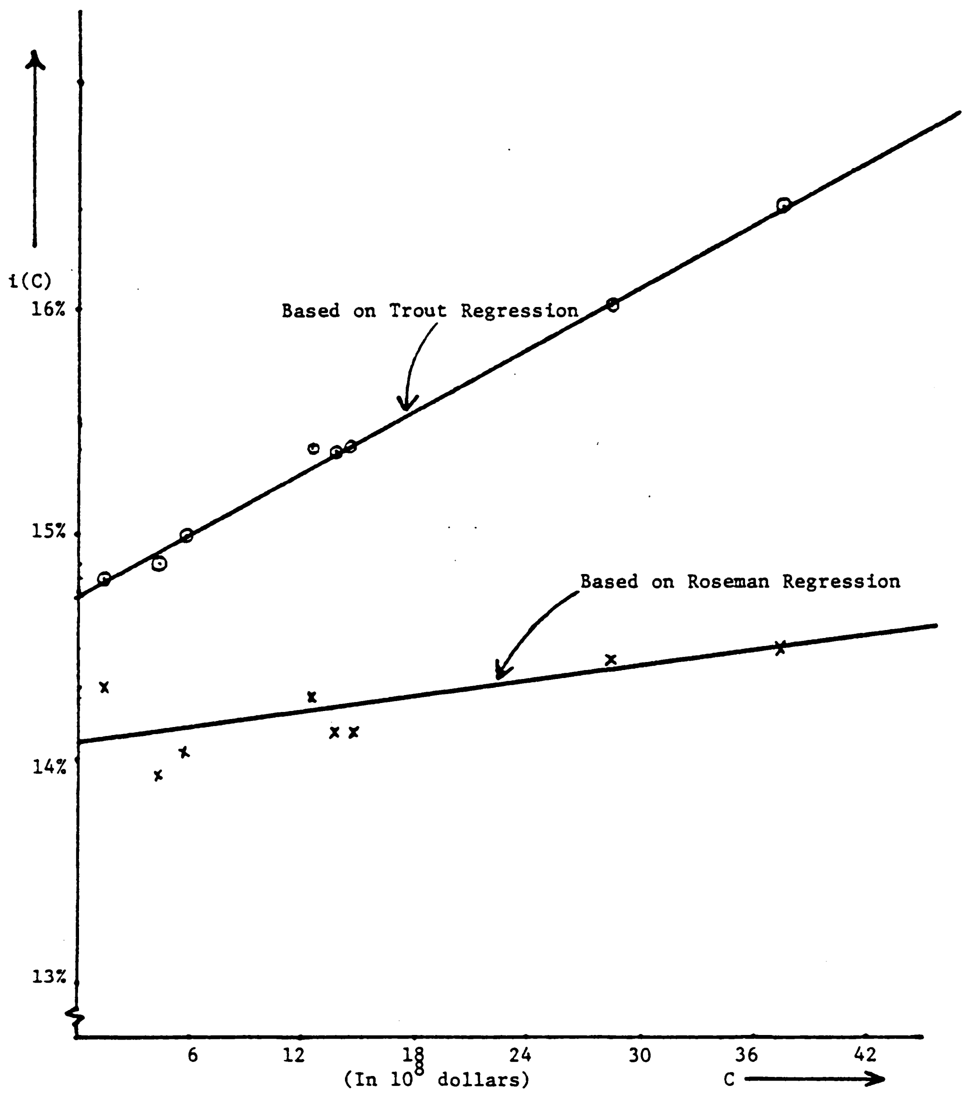

Figure 8.2. Estimated Capital Supply Curves

Table 8.5

Sensitivity of i(C) to Regulatory Parameters

Agent of Change	Roseman Regression		Trout Regression	
	Most Capital Intensive Plan	Least Capital Intensive Plan	Most Capital Intensive Plan	Least Capital Intensive Plan
	Before Tax Cost of Capital	Before Tax Cost of Capital	Before Tax Cost of Capital	Before Tax Cost of Capital
Lag = 0	14.50%	14.30%	16.46%	14.82%
Lag = 2 yr.	14.63%	13.85%	17.02%	14.99%
CWIP % Allowed = 0%	14.62%	14.31%	16.52%	14.83%
CWIP % Allowed = 50%	14.17%	14.26%	16.27%	14.81%
CWIP % Allowed = 100%	13.99%	14.29%	16.35%	14.86%
Normalization Accounting	13.86%	13.57%	16.02%	14.92%
Flow-through Accounting	15.34%	14.60%	16.41%	14.76%
AFUDC Rate = 5%	14.16%	14.26%	16.48%	14.81%
AFUDC Rate = 10%	14.68%	14.32%	16.45%	14.83%

<u>Base Reference Data</u>

Private Utilities
Lag = 0
CWIP = 14.2%
Flow-through % = 21.5%
AFUDC Rate = 8.23%

Public Utilities
Lag = 1 yr.
CWIP = 12.2%
Flow-through % = 21.5%
AFUDC Rate = 9.27%

From Table 8.5 one observes that, as regulatory lag increases, as expected, the cost of capital increases. The model was run with an inflation rate of 0%. If the future data represent a significant inflation rate, most likely a more severe effect of lag would be encountered.

Similarly, expected trends in the cost of capital are encountered as the percent CWIP allowed in the rate base is increased. The normalization accounting, in general, leads to a lower cost of capital curve than the flow-through accounting.

As AFUDC rate increases the cost of capital increases (in general) as depicted in Table 8.5. This is counter-intuitive because as AFUDC rate increases, the firm's financial situation should be better and cost of capital should fall. The large negative weights give to AFUDC as a percent of net income in both the Trout and Roseman regressions explain this apparently counter-intuitive result. The increase in the earnings are being more than offset by the decreasing quality of earnings.

Some other counter-intuitive results are obtained. For example, when all of CWIP is allowed in the rate base, under the Roseman equation we produce a decreasing cost of capital curve. If all of CWIP is allowed in the rate base and regulatory lag is zero, then regulation is essentially equivalent to Averch-Johnson type continuous regulation. Thus, the apparently counter-intuitive result of the decreasing cost of capital curve might be a restatement of the A-J type capital bias.

In conclusion, the regulatory parameters affect the cost of capital curve for a regulated electric utility significantly. With the present regulatory assumptions, a rising cost of capital curve is reasonable. But, if the regulatory parameters are changed significantly, a regulated firm, unlike an unregulated firm, could exhibit a constant or even declining cost of capital curve.

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APPENDIX A

In this appendix we present the mathematical arguments underlying the suggested surrogate capital and fuel costs in Chapter 4. First, we restate the capacity planning problem in a form suitable for the following development.

Let us consider a single period capacity expansion planning problem in which the equipment has no salvage value at the end of the period. Let k_ℓ denote the capital cost (unannualized) for equipment type ℓ and g_ℓ denote the fuel cost for equipment type ℓ. Also, let the total number of equipment types be N. Without loss of generality, assume

$$k_1 > k_2 \;\ldots\; > k_N \geqq 0$$

and

$$0 \leqq g_1 < g_2 \;\ldots\; < g_N \quad .$$

Let $h(\cdot)$ denote the single period load curve. Let x_ℓ denote the capacity of plant type ℓ. Since the cost minimizing optimal solution will always satisfy the merit order dispatching property, one can write the capacity planning problem as,

$$\text{Min} \sum_{\ell=1}^{N} k_\ell x_\ell + \sum_{\ell=1}^{N} g_\ell \int_{x_1 + \dots + x_{\ell-1}}^{x_1 + \dots + x_\ell} h^{-1}(q)\,dq$$

$$\sum_{\ell=1}^{N} x_\ell = h(0) \qquad \text{(A.1)}$$

$$x_\ell \geqq 0$$

Note that the program (A.1) can be solved by a simple breakeven chart based technique as shown in Fig. 3.3(a) and Fig. 3.3(b). Also, note that the ordinate intercepts of the straight lines in Fig. 3.3(a) are the k_ℓ's and the slopes of the straight lines are g_ℓ's.

Next, consider a T-period problem and also assume that the equipment types are usable until the end of the horizon. Such a T-period problem can be written as,

$$\text{Min} \sum_{\ell=1}^{N} \sum_{t=1}^{T} \frac{k_{\ell t}(x_{\ell t} - x_{\ell,t-1})}{(1+i)^{t-1}} + \sum_{\ell=1}^{N} \sum_{t=1}^{T} \frac{g_{\ell t}}{(1+i)^{t-1}} \int_{x_{1t}+\dots+x_{\ell-1,t}}^{x_{1t}+\dots+x_{\ell t}} h_t^{-1}(q)\,dq$$

$$\text{s.t.} \quad \sum_{\ell=1}^{N} x_{\ell t} = h_t(0), \quad t=1, \dots T \qquad \text{(A.2)}$$

$$x_{\ell t} \geqq x_{\ell, t-1}, \quad t=2, \dots T$$

$$x_{\ell t} \geqq 0$$

Here, $k_{\ell t}$, $g_{\ell t}$ are the capital and fuel costs for equipment type ℓ in period t, respectively. Also, i is the discount rate and h_t is the load curve in period t.

It seems intuitively plausible that if $x_{\ell t} > x_{\ell ,t-1}$ for all $\ell \varepsilon \{1,\ldots.,N\}$ and $t\varepsilon\{2,\ldots.,T\}$, then program (A.2) should be solvable by a sequence of breakeven charts, one for each period. We now find what capital costs should be used in this sequence of single period breakeven charts.

In [47] Program (A.2) is shown to be convex. If the optimal solution satisfied the property $x_{\ell t} \geqq x_{\ell ,t-1}$ for $\ell \varepsilon\{1,\ldots.,N\}, t\varepsilon\{2,\ldots.,T\}$ then program (A.2) should have the same optimal solution as program (A.3) below:

$$\text{Min} \sum_{\ell=1}^{N} \sum_{t=1}^{T} \frac{k_{\ell t}(x_{\ell t}-x_{\ell ,t-1})}{(1+i)^{t-1}} + \sum_{\ell=1}^{N} \sum_{t=1}^{T} \frac{g_{\ell t}}{(1+i)^{t-1}} \int_{x_{1t}+\ldots x_{\ell-1,t}}^{x_{1t}+\ldots+x_{\ell t}} h_t^{-1}(q)dq$$

$$\text{s.t.} \quad \sum_{\ell=1}^{N} x_{\ell t} = h_t(0), \quad t=1, \ldots., T \qquad \text{(A.3)}$$

$$x \geqq 0$$

Now, program (A.3) can be decomposed into T simple breakeven chart type problems, (problems of same algebraic form as (A.1)), as follows. For periods t = 1, 2, ..., T-1 one obtains

$$\text{Min} \; \frac{1}{(1+i)^{t-1}} \left[\sum_{\ell=1}^{N} \left(k_{\ell t} - \frac{k_{\ell,t+1}}{1+i} \right) x_{\ell t} + \sum_{\ell=1}^{N} g_{\ell t} \int_{x_{1t}+\ldots+x_{\ell-1,t}}^{x_{1t}+\ldots+x_{\ell t}} h_t^{-1}(q)dq \right]$$

$$\text{s.t.} \quad \sum_{\ell=1}^{N} x_{\ell t} = h_t(0) \tag{A.4}$$

$$x_{\ell t} \geqq 0, \quad t=1, \ldots, T-1$$

In addition, the Tth period problem will be,

$$\text{Min} \; \frac{1}{(1+i)^{T-1}} \left[\sum_{\ell=1}^{N} k_{\ell T} x_{\ell T} + \sum_{\ell=1}^{N} g_{\ell T} \int_{x_{1T}+\ldots+x_{\ell-1,T}}^{x_{1T}+\ldots+x_{\ell T}} h_T^{-1}(q)dq \right]$$

$$\text{s.t.} \quad \sum_{\ell=1}^{N} x_{\ell T} = h_T(0) \tag{A.5}$$

$$x_{\ell T} \geqq 0, \quad \ell=1, \ldots, N$$

If we compare (A.4) and (A.5) with (A.1), one obtains the following capital costs to be used in the single period breakeven charts:

(a) $\left[k_{\ell t} - \dfrac{k_{\ell,t+1}}{1+i} \right]$ for equipment type ℓ in t^{th} period breakeven chart and,

(b) $k_{\ell t}$ for equipment type ℓ in the last period.

Note that (a) is equivalent to subtracting the salvage value of the equipment ℓ in at the end of period. The salvage value at the end of period t is the capital cost in the period t+1. Also, note that since T is the last period in the horizon, the salvage value is not imputed in (b). Now, if we consider an infinite horizon problem with infinite equipment lifetimes, one obtains that $\left[k_{\ell t} - \frac{k_{\ell,t+1}}{1+i}\right]$ is the appropriate capital cost to be used in all periods. If the capital costs do not change over time, the above expression reduces to, $\frac{ik_{\ell t}}{1+i}$, which is equivalent to annualizing over infinite life as shown in Fig. 4.1. If the capital costs are forecasted to grow at rate α_ℓ for equipment type ℓ, in an analogous manner one obtains $\frac{k_{\ell t}[i-\alpha_\ell]}{1+i}$ as the appropriate capital costs to be used in the single period breakeven charts.

Next assume that the equipment lives are finite. We still restrict ourselves to the case when the optimal solution is such that capacities of all equipment types expand in all periods. Since the optimal capacity of all the equipment types expand in all periods, it follows that all the equipment retired is replaced at the end of its life. So, in this context, when one decides to install $x_{\ell t}$ amount of capacity for equipment type ℓ in period t, we are also deciding to make the replacements at the end of its life, n_ℓ. Such a restriction can be imposed on our decisions because it is assumed that the optimal solution to the unrestricted problem is such that the capacities of all equipment types expand in all periods (This is a case in which, conceivably, a sequence of breakeven charts should be able to solve the multiperiod problem). So, now our decision to install $(x_{\ell t}-x_{\ell,t-1})$ capacity of equipment type ℓ in period t is costing us not only the initial installation cost, but also the subsequent replacement costs. If the installation cost of equipment type ℓ in period t is $k_{\ell t}$/kW, then the coefficient of $(x_{\ell t}-x_{\ell,t-1})$ in program (A.2) should be,

$$k_{\ell t} + \frac{k_{\ell,t+n_\ell}}{(1+i)^{n_\ell}} + \frac{k_{\ell,t+2n_\ell}}{(1+i)^{2n_\ell}} + \ldots. \qquad \text{(A.6)}$$

Thus, if capital costs do not change with time, then the appropriate capital costs to be used are,

$$\frac{i\, k_{\ell t}}{(1+i)[1 - \frac{1}{(1+i)^{n_\ell}}} \quad .$$

A straightforward analysis shows that the above is equivalent to annualizing $k_{\ell t}$ over the finite life n_ℓ. Thus, the above capital costs generalizes the Soyster-Murphy [48] annualized capital costs.

Similarly, if the capital costs are forecasted to grow at rate α_ℓ for the equipment type ℓ, then one can obtain the following capital cost to be used in breakeven charts,

$$\frac{k_{\ell t}\,[i - \alpha_\ell]}{(1+i)\left[1 - \left(\frac{1+\alpha_\ell}{1+i}\right)^{n_\ell}\right]}$$

The interpretation of the above capital costs is shown in Fig. 4.2.

Next, we prove two theorems which form the basis for the strategy of selecting the appropriate fuel prices in the single period breakeven charts presented in Chapter 4. In these theorems, we assume that the capital costs do not change with time so that the ordinary annualization is valid.

Theorem A.1

Consider a multiperiod capacity expansion planning problem and assume that the load curve is concave. Also assume that no retirements are allowed. Denote the annual growth in demand by β and let the fuel prices grow at rate α, where $\alpha > \beta \geqq 1$. If the optimal solution is such that the ℓth equipment type is expanded in the first period, then the $(\ell+1)$st equipment type does not expand in period 2 through T.

Proof:

Let k_ℓ denote the annualized capital cost for all periods and $x_{\ell t}$ denote the cumulative capacity of equipment type ℓ in period t. One can write the multiperiod capacity expansion planning problem as,

$$\text{Min} \sum_{t=1}^{T} \sum_{\ell=1}^{N} \frac{k_\ell x_{\ell t}}{(1+i)^{t-1}} + \sum_{t=1}^{T} \sum_{\ell=1}^{N} \frac{g_{\ell 1}\ \alpha^{t-1}}{(1+i)^{t-1}} \int_{x_{1t}+\dots+x_{\ell-1,t}}^{x_{1t}+\dots+x_{\ell t}} h_t^{-1}(q)dq$$

$$\sum_{\ell=1}^{N} x_{\ell t} = h_t(0) \qquad (\lambda_t) \qquad \text{(A.7)}$$

$$x_{\ell,t+1} \geqq x_{\ell t} \qquad (\mu_{\ell t})$$

$$x \geqq 0$$

Here, λ_t and $\mu_{\ell t}$ are the dual variables associated with the corresponding constraints. By the assumption one has $x^*_{\ell 1} > 0$ (x^* denotes the multiperiod optimal solution). Hence, from feasibility of program (A.7) it follows that,

$$x^*_{\ell t} > 0 \quad \text{for all } t \in [1,T].$$

The Kuhn-Tucker conditions for $x_{\ell t}$ give the following,

$$\frac{k_\ell}{(1+i)^{t-1}} + \frac{\alpha^{t-1}}{(1+i)^{t-1}} [(g_{\ell 1}-g_{\ell+1,1})b_{\ell t}+\ldots+(g_{N-1,1}-g_N)b_{N-1,t}] + \lambda_t$$

$$+ \mu_{\ell t} - \mu_{\ell,t-1} = 0 \qquad \text{(A.8)}$$

where

$$b_{\ell t} = h_t^{-1} (x_{1t} + x_{2t} + \ldots + x_{\ell t}).$$

Thus, $b_{\ell t}$ is the minimum capacity factor at which the equipment type ℓ operates in period t. Summing (A.8) for all $t \in [1,T]$ one obtains,

$$k_\ell \left[\sum_{j=1}^{T} \left(\frac{1}{1+i}\right)^{j-1}\right] + (g_{\ell 1} - g_{\ell+1,1}) \sum_{j=1}^{T} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} b_{\ell j}\right] + \ldots.$$

$$+ (g_{N1,1} - g_{N1}) \sum_{j=1}^{T} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} b_{N-1,j}\right]$$

$$+ \sum_{j=1}^{T} \lambda_j = 0 \qquad (A.9)$$

Similarly, for $x_{\ell+1}$ one can obtain,

$$k_{\ell+1} \left[\sum_{j=1}^{T} \left(\frac{1}{1+i}\right)^{j-1}\right] + (g_{\ell+1,1} - g_{\ell+2,1}) \sum_{j=1}^{T} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} b_{\ell+1,j}\right]$$

$$+ \ldots. + (g_{N-1,1} - g_{N1}) \sum_{j=1}^{T} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} b_{N-1,j}\right]$$

$$+ \sum_{j=1}^{T} \lambda_j \geqq 0 \qquad (A.10)$$

From (A.9) and (A.10) one obtains,

$$(k_\ell - k_{\ell+1}) \sum_{j=1}^{T} \left(\frac{1}{1+i}\right)^{j-1} + (g_{\ell 1} - g_{\ell+1,1}) \sum_{j=1}^{T} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} b_{\ell j}\right] \leqq 0 \qquad (A.11)$$

Contrary to the statement of the theorem, assume, in the optimal solution, that the $(\ell+1)$st equipment expands in some periods 2 through T. Let the first period in which the equipment type $(\ell+1)$ expands be denoted by $(t'+1)$. Summing the Kuhn-Tucker conditions for $x_{\ell,t'+1}$ to $x_{\ell T}$ one can obtain,

$$k_\ell \left[\sum_{j=t'+1}^{T} \left(\frac{1}{1+i}\right)^{j-1}\right] + (g_{\ell 1}-g_{\ell+1,1}) \sum_{j=t'+1}^{T} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} b_{\ell j}\right] + \ldots.$$
$$+ (g_{N-1,1}-g_{N1}) \sum_{j=t'+1}^{T} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} b_{N-1,j}\right]$$
$$+ \sum_{j=t'+1}^{T} \lambda_j - u_{\ell t'} = 0 \qquad \text{(A.12)}$$

Similarly, summing Kuhn-Tucker conditions for $x_{\ell+1,t'+1}$ to $x_{\ell+1,T}$ we obtain,

$$k_{\ell+1} \left[\sum_{j=t'+1}^{T} \left(\frac{1}{1+i}\right)^{j-1}\right] + (g_{\ell+1,1}-g_{\ell+2,1}) \sum_{j=t'+1}^{T} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} b_{\ell+1,j}\right]$$
$$+\ldots. + (g_{N-1,1}-g_{N1}) \sum_{j=t'+1}^{T} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} b_{N-1,j}\right]$$
$$+ \sum_{j=t'+1}^{T} \lambda_j - \mu_{\ell+1,t'} = 0 \qquad \text{(A.13)}$$

Since the equipment type $(\ell+1)$ expands in period $(t'+1)$, it follows that $\mu_{\ell+1,t'} = 0$.

From (A.12) and (A.13) one obtains,

$$(k_\ell - k_{\ell+1}) \sum_{j=t'+1}^{T} \left(\frac{1}{1+i}\right)^{j-1} + (g_{\ell 1} - g_{\ell+1,1}) \sum_{j=t'+1}^{T} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} b_{\ell j}\right] \geq 0$$

(A.14)

For a concave load curve, as illustrated in Fig. A.1,

$$\beta\, b_{\ell,j+1} = \beta \left[h_{j+1}^{-1} \left(x_{1,j+1} + \ldots. + x_{\ell,j+1}\right)\right]$$

$$= \beta \left[h_{j+1}^{-1} \left\{ h_{j+1}(0) - (x_{\ell+1,j+1} + \ldots. + x_{N,j+1}) \right\}\right]$$

$$= \beta \left[h_{j}^{-1} \left\{\frac{h_{j+1}(0) - (x_{\ell+1,j+1} + \ldots. + x_{N,j+1})}{\beta} \right\}\right]$$

(since $h_{j+1}(\cdot) = \beta\, h_j(\cdot)$)

$$= \beta \left[h_{j}^{-1} \left\{h_j(0) - \frac{(x_{\ell+1,j+1} + \ldots. + x_{N,j+1})}{\beta} \right\}\right]$$

$$\geq \left[h_{j}^{-1} \left\{h_j(0) - (x_{\ell+1,j+1} + \ldots. + x_{N,j+1}) \right\}\right]$$

(see Figure A.1)

$$\geq \left[h_{j}^{-1} \left\{ h_j(0) - (x_{\ell+1,j} + \ldots. + x_{Nj}) \right\}\right]$$

$$= b_{\ell j}$$

Hence, $\beta\, b_{\ell,j+1} \geq b_{\ell j}$. (A.15)

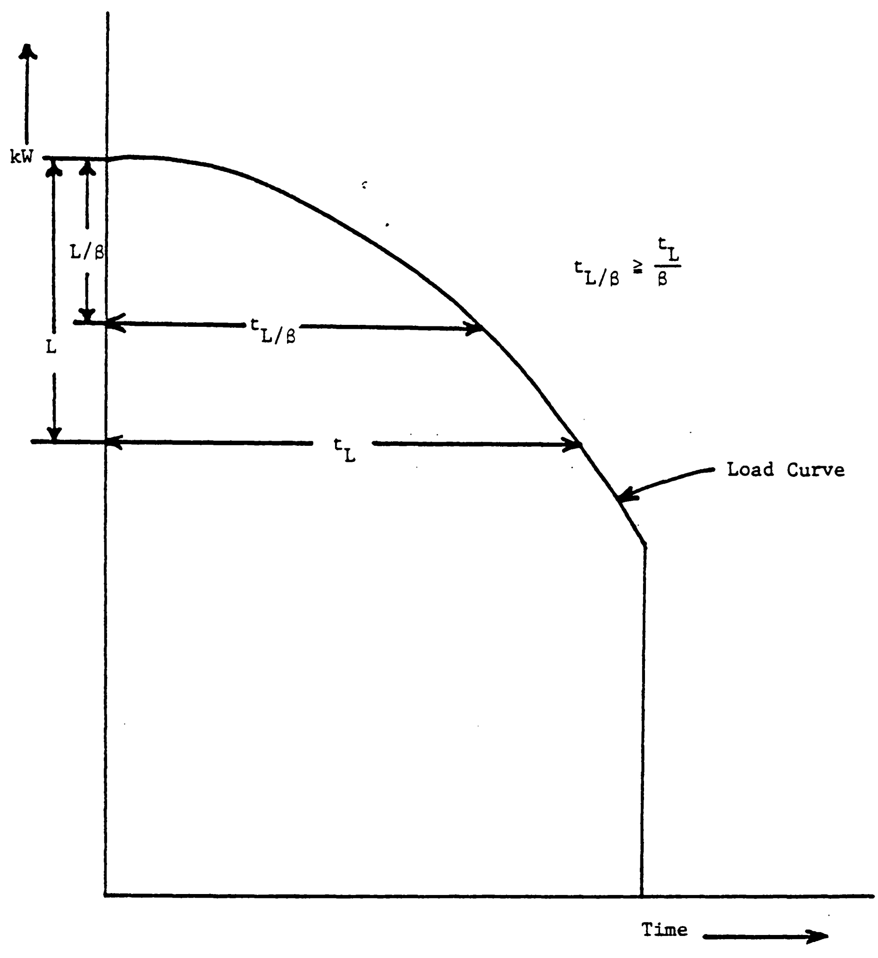

Figure A.1. A Concave Load Curve

Since $\alpha > \beta$, from (A.15) it follows that,

$$\sum_{j=t'+1}^{T} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} \; b_{\ell j} \right] > b_{\ell,t'+1} \; \alpha^{t'} \sum_{j=t'+1}^{T} \left(\frac{1}{1+i}\right)^{j-1} \tag{A.16}$$

From (A.14) and (A.16) it then follows that,

$$b_{\ell,t'+1} < \frac{k_\ell - k_{\ell+1}}{\alpha^{t'} (g_{\ell+1,1} - g_{\ell 1})} \tag{A.17}$$

Subtracting (A.14) from (A.11) we obtain,

$$(k_\ell - k_{\ell+1}) \sum_{j=1}^{t'} \left(\frac{1}{1+i}\right)^{j-1} + (g_{\ell 1} - g_{\ell+1,1}) \sum_{j=1}^{t'} \left[\frac{\alpha^{j-1}}{(1+i)^{j-1}} \; b_{\ell j} \right] \leqq 0$$

Using (A.15) again one can obtain,

$$b_{\ell t'} \geqq \frac{k_\ell - k_{\ell+1}}{\alpha^{t'-1} (g_{\ell+1,1} - g_{\ell 1})} \tag{A.18}$$

From (A.17) and (A.18),

$$\beta \; b_{\ell,t'+1} < \frac{\beta}{\alpha^{t'}} \; \frac{k_\ell - k_{\ell+1}}{g_{\ell+1,1} - g_{\ell 1}} < \frac{k_\ell - k_{\ell+1}}{\alpha^{t'-1} (g_{\ell+1,1} - g_{\ell 1})} < b_{\ell t'},$$

which is a contradiction to (A.15). Hence, the $(\ell+1)$st equipment type will not expand in period 2 through T and the theorem is proven.

From the above theorem the following corollary follows.

Corollary A.1

Assume the load curve is concave and $\alpha > \beta \geqq 1$. If in the optimal solution some positive amount of baseload equipment is expanded in the first period, then no other equipment type will expand in periods 2 through T.

Proof:

From the above theorem, equipment type 2 will not expand in periods 2 through T. Now consider two cases:

(i) $x^*_{21} = 0$. In this case $x^*_{2t} = 0$ for all $t \varepsilon \{1, \ldots, T\}$. So equipment type 2 can be removed from the problem and the remaining equipment types can be renumbered.

(ii) $x^*_{21} > 0$. In this case, since equipment type 2 is expanded in the first period solution, it follows from Theorem A.1 that equipment type 3 cannot expand in periods 2 through T.

Proceeding as above the corollary is proven for any finite N.

Next, we study how to replicate the first period part of the solution to program (A.7) when $\alpha > \beta \geqq 1$. Here, we will assume the load curve is linear, so Theorem A.1 and Corollary A.1 hold. If some amount of baseload is added in the first period, then Corollary A.1 implies $x^*_{\ell t} = x^*_{\ell,t+1}$ for $\ell\varepsilon\{2,\ldots,N\}, t\varepsilon\{1,\ldots,T\}$. From the above fact, program (A.7) can be rewritten as,

$$\text{Min} \sum_{t=1}^{T}\sum_{\ell=2}^{N} \frac{(k_\ell-k_1)x_{\ell 1}}{(1+i)^{t-1}} + \sum_{t=1}^{T}\sum_{\ell=2}^{N} \frac{(g_{\ell 1}-g_{11})\alpha^{t-1}}{(1+i)^{t-1}} \int_{x_{1t}+\cdots+x_{\ell-1,t}}^{x_{1t}+\cdots+x_{\ell t}} h_t^{-1}(q)\,dq$$

$$\begin{aligned} \text{s.t.}\quad & x_{\ell t} \geqq 0 \qquad \text{for } \ell=2, \ldots N,\ t=1,\ldots,T \\ & x_\ell^t = x_\ell^{t+1} \qquad \text{for } \ell=2, \ldots N,\ t=1,\ldots,T \end{aligned} \tag{A.19}$$

For a linear load curve, this program becomes,

$$\text{Min} \sum_{\ell=2}^{N}\sum_{t=1}^{T} \frac{(k_\ell-k_1)x_{\ell 1}}{(1+i)^{t-1}} + \sum_{\ell=2}^{N}\sum_{t=1}^{T} \frac{(g_{\ell 1}-g_{11})\alpha^{t-1}}{(1+i)^{t-1}} \frac{x_{\ell t}(x_{Nt}+\cdots+x_{\ell+1,t}+\frac{x_{\ell t}}{2})}{\beta^{t-1}\,P}$$

$$\begin{aligned} \text{s.t.}\quad & x_{\ell t} \geqq 0 \qquad \text{for } \ell=2, \ldots,N,\ \ t=1, \ldots, T, \\ & x_{\ell t} = x_{\ell,t+1} \end{aligned} \tag{A.20}$$

Here, P is the peak load in the first period. The first order stationary conditions for program (A.20) imply,

$$\sum_{\ell=j+1}^{N} x_{\ell 1}^{*} = P \frac{(k_j - k_{j+1}) \sum_{t=1}^{T} (\frac{1}{1+i})^{t-1}}{(g_{j+1,1} - g_{j1} \sum_{t=1}^{T} [\frac{\alpha}{\beta(1+i)}]^{t-1}} \text{, if } x_{j1}^{*} > 0,$$

for $j \varepsilon \{1,\ldots.,N-1\}$.

Thus, the first period optimal solution can be associated with breakeven points given by,

$$\frac{(k_j - k_{j+1}) \sum_{t=1}^{T} (\frac{1}{1+i})^{t-1}}{(g_{j+1,1} - g_{j1}) \sum_{t=1}^{T} \left[\frac{\alpha}{\beta(1+i)}\right]^{t-1}} .$$

To obtain the above set of breakeven points, the fuel prices to be used in the breakeven chart should be,

$$g_j^S = \frac{g_{j1} \sum_{t=1}^{T} \left[\frac{\alpha}{\beta(1+i)}\right]^{t-1}}{\sum_{t=1}^{T} (\frac{1}{1+i})^{t-1}} \quad \text{for } j \varepsilon \{1,\ldots.,N\}$$

Next, we prove the optimality of the use of current fuel price if $\beta \geqq \alpha \geqq 1$ for convex load curves, i.e., if the load curve is convex and demand is growing at least as fast as fuel prices, then the use of current (period t=1) fuel prices in a single period breakeven chart will replicate the first period part of the multiperiod optimal solution.

Theorem A.2

Consider a T-period capacity expansion planning problem. Let the load curve be convex and grow at rate β and let the fuel vector grow at rate α. If $\beta \geqq \alpha \geqq 1$ and a positive amount of equipment 1 is added in the first period in the multiperiod optimal solution, then using the first period's fuel prices in a single period model will produce the first period part of the multiperiod optimal solution.

Proof:

The breakeven point $b_{\ell t}$, for the single period problem for the period t, is given by,

$$b_{\ell t} = \frac{k_{\ell} - k_{\ell+1}}{\alpha^{t-1}(g_{\ell+1,1} - g_{\ell 1})}$$

Also,

$$\begin{aligned} x_{\ell t} &= h_t\,(b_{\ell t}) - h_t\,(b_{\ell-1,t}) \\ &= \beta^{t-1} \left[h_1\,(b_{\ell t}) - h_1\,(b_{\ell-1,t}) \right] \\ &= -\beta^{t-1}\, s_{\ell t}[\,(b_{\ell t} - b_{\ell-1,t})\,] \end{aligned} \tag{A.21}$$

Here, $s_{\ell t}$ is the slope of the chord $A_t B_t$ as shown in Fig. A.2. Equation (15) can be rewritten as,

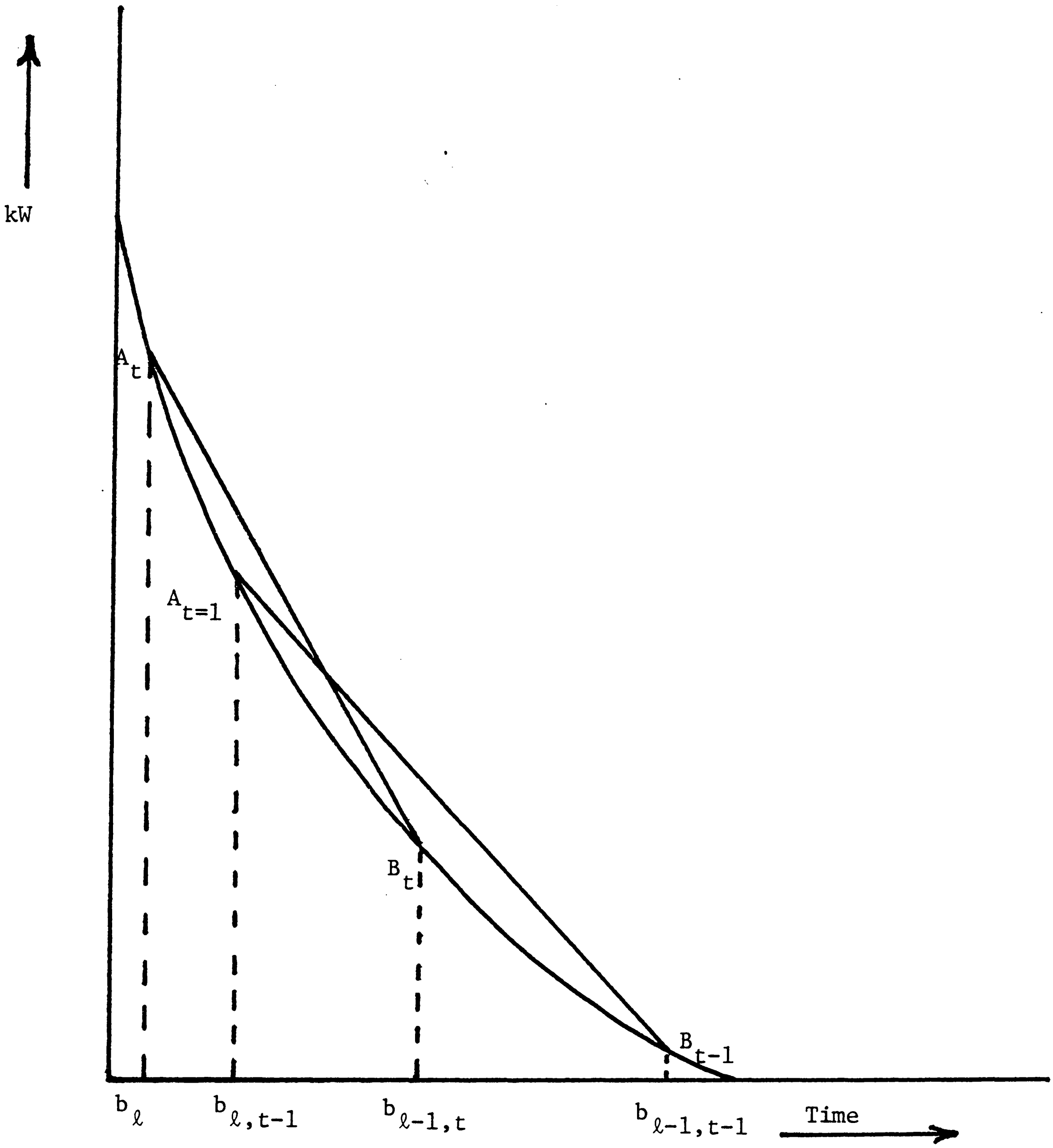

Figure A.2. A Convex Load Curve

$$x_{\ell t} = -\frac{\beta^{t-1}}{\alpha^{t-1}} \left[\frac{k_\ell - k_{\ell+1}}{g_{\ell+1,1} - g_{\ell 1}} - \frac{k_{\ell-1} - k_\ell}{g_{\ell 1} - g_{\ell-1,1}} \right] s_{\ell t}$$

Now, if $s_{\ell t} \leqq s_{\ell,t-1}$, then $x_{\ell t} \geqq x_{\ell,t-1}$. Since $s_{\ell t}$ is the slope of $A_t B_t$ and $s_{\ell,t-1}$ is the slope of $A_{t-1}B_{t-1}$ and since A_t is to the left of A_{t-1} and B_t is to the left of B_{t-1}, for a convex h_1 we have $s_{\ell t} \leqq s_{\ell,t-1}$ and the theorem is proven.

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FINANCIAL AND REGULATORY CONSIDERATIONS IN THE
CAPACITY EXPANSION PLANNING FOR
ELECTRIC UTILITY INDUSTRY

by

Sampat Kumar Saraf

(ABSTRACT)

Due to large amounts of capital involved, the financial considerations gain paramount importance in the capacity planning decision of an electric utility. Three important financial issues are choice of appropriate capital and fuel costs, effect of regulation and scarcity of capital. The first section of the dissertation is devoted to an overview of the electric utility industry and literature review.

In the second section, we address the issue of selection of appropriate capital and fuel costs. When a time-stepped approach is used for electric utility capacity planning, an important question is what fuel and capital costs should be used in a single period model to replicate the first period part of the multiperiod optimal solution. We address this question and show that a generalization of Baughman-Joskow surrogate fuel price is optimal for the case of a linear load duration curve. Similarly, a generalization of Soyster-Murphy annualization process is obtained for the selection of appropriate surrogate capital costs.

In the third section, capacity planning for a regulated utility is analyzed when the objective of the utility is value maximization. the resulting mathematical program is shown to have the same algebraic form as the cost minimization capacity planning model. The optimal solution under the value maximizing assumption is consistent with several important results of regulated economics. The value maximizing approach is extended to include certain inperfections like lead times and finite equipment lifetimes.

In the final section, a single period capacity expansion model is developed for a utility faced with a rising supply curve of capital. The properties of the optimal solution to this model are analyzed. It is shown that if one uses a constant cost of capital model for a utility faced with a rising cost of capital, one produces an overly capital intensive solution. A graphical procedure for solving the rising cost of capital, single period model is developed and presented. A technique for estimating the capital supply curve for the electric utility industry is developed. The sensitivity of the capital supply curve to various regulatory parameters is analyzed and the capital supply curve is found to be very sensitive to regulatory parameters.