Valuation Methods for Capital Investment in Merchant Power Plants

by

Nathan E. Hottle

Bachelor of Science in Physics-Engineering and Computer Science
Washington and Lee University, 1997

Submitted to the Engineering Systems Division
in Partial Fulfillment of the Requirements for the Degree of

Master of Science in Technology and Policy

at the

Massachusetts Institute of Technology

September 2003

Signature of Author..
Technology and Policy Program, Engineering Systems Division
August 14, 2003

Certified by... ....
Paul L. Joskow
Elizabeth and James Killian Professor of Economics and Management
Thesis Supervisor

Accepted by.......... ....
Dava J. Newman
Associate Professor of Aeronautics and Astronautics and Engineering Systems
Director, Technology and Policy Program

Valuation Methods for Capital Investment in Merchant Power Plants

By

Nathan E. Hottle

Submitted to the Engineering Systems Division on August 14, 2003
in Partial Fulfillment of the Requirements for the Degree of
Master of Science in Technology and Policy

ABSTRACT

Wholesale electricity in the U.S. and many other countries is increasingly being supplied by unregulated firms competing to sell their product in competitive markets. Developers of the new merchant plants face a different set of risks than the regulated vertically-integrated utilities that formerly owned the generating resources that supplied electricity to customers in their service area.

This thesis evaluates the impact that industry restructuring will have on investments in capital-intensive electricity generation technologies and assesses the applicability of traditional economic valuation methods to investment decisions in a competitive wholesale electricity market. The evidence is presented through the use of a case study on the likelihood of investment in new nuclear power plants in both organizational arrangements as predicted by two economic valuation methods.

The results suggest that merchant developers will favor less capital-intensive technologies and that the traditional valuation method for power plant investment fails to capture the total effect on investment decisions of the new market arrangement. Economic studies that ignore the true nature of merchant plant investment will provide misleading conclusions regarding the relative competitiveness of generating technologies.

Thesis Supervisor: Paul L. Joskow
Title: Elizabeth and James Killian Professor of Economics and Management

[THIS PAGE LEFT INTENTIONALLY BLANK]

Table of Contents

List of Tables

List of Figures

Acknowledgements

I would like to express my gratitude to Paul Joskow for his guidance in this research and for the generous contribution of his time. I am also grateful to John Deutch and Ernie Moniz for providing the opportunity to participate in their MIT Study on the Future of Nuclear Power, and to the Alfred P. Sloan Foundation for financial support. Finally, I would like to thank Dani Mesko, who kept me on track by offering encouragement when I needed it most.

1 Introduction

The electric power sector in the U.S. is undergoing a transition in which the traditional power companies, regulated monopolies with full vertical integration of all components of power supply, are disappearing and are being replaced by collections of firms and institutions that collectively provide electricity services to consumers. These new entities rely to a greater extent on market transactions to efficiently allocate scarce resources, which, it is hoped, will lead to lower production costs and lower electricity rates for consumers. Federal and state regulatory agencies are responsible for regulating different segments of the industry and reform efforts are underway at both levels. The focus here is on wholesale electricity generation and the emergence of unregulated "merchant" generating plants competing to supply the market.

Wholesale competition will likely have some effect in the short-term on operating practices at existing generating plants, but this thesis is concerned with long-term behavior in the market, involving decisions to invest in new generating capacity. Market participants face a different set of risks and incentives than did their regulated predecessors and valuation techniques for power plant investment must accurately reflect these new conditions. This thesis investigates the effect that the new competitive market environment is likely to have on investment decisions in new generating capacity, specifically on the selection of generating technology. The traditional regulated utility valuation model is applied using parameter values representative of regulated utilities to provide a baseline for comparison. The same model is then applied to merchant plant investments by adjusting the financing assumptions to reflect the new market conditions. Finally, a separate valuation model that is assumed to more accurately capture the investment decision in a competitive wholesale market is applied to test the performance of the traditional model. Since many economic assessments of future generating technologies rely on models similar to the traditional utility valuation model, it is important to establish under what conditions it provides an accurate representation of actual investor behavior.

The assessment is performed through a case study on the economic viability of future investments in base load nuclear power systems in competitive wholesale markets. The case of nuclear power is a pertinent one because many countries, including the U.S., are reconsidering their commitment to nuclear power to meet energy and environmental policy goals in the coming decades. The thesis proceeds as follows:

Chapter 2: Introduces the structure of the electric power industry both prior to and as a result of restructuring and regulatory reform initiatives. The chapter discusses pricing mechanisms in both frameworks and the impact that restructuring has on the level of risk that project developers face.

Chapter 3: Presents the cost and performance attributes of base load generation technologies that are likely to have the largest impact on investments in merchant plants. The three base load technologies used in the analysis are defined, along with the associated baseline cost and performance assumptions.

Chapter 4: Introduces the revenue requirement model as it is used to value investments made by a regulated utility. The applicability of the model to the unique situation of regulated monopoly is discussed and results of the analysis are presented that identify the conditions under which a regulated utility would invest in new nuclear power plants.

Chapter 5: Begins by adapting the revenue requirement model to merchant plant investment by changing the financing assumptions to more accurately reflect the merchant developer's cost of capital. The impact of the change is highlighted in relation to the regulated utility case. The chapter then introduces a new valuation model that is more capable of capturing the economic realities of merchant plant investment and new model results are presented with different implications for nuclear plant investment. The differences between the two valuation models are discussed and it is shown that the traditional model's inherent assumptions may introduce significant errors in merchant plant valuation.

Chapter 6: Discusses other factors that are important when considering investments in a competitive merchant plant environment that go beyond simple discounted cash flow analysis. The option value gained from the inherent flexibility of certain technologies in the face of market uncertainties can be significant for power plant investments. Project developers also have to consider the impact that an investment will have on its financial health as perceived by potential investors. These additional factors are not treated with rigor in this thesis, but it is recognized that they may be among the most important factors when real investment decisions are made.

Chapter 7: Concludes the thesis by summarizing the observations on merchant plant investment and valuation models.

The valuation models used in the analysis are described in detail in two appendices.

2 Electricity Generation and Industrial Structure

Electric power sector restructuring is occurring in many parts of the world, including the United States. Traditionally supplied by vertically integrated utilities, electricity increasingly is being sold in competitive wholesale and retail markets. Competitive electricity markets present new risks for companies owning generation assets that will require a reexamination of the criteria used to evaluate capital investments. Prior to discussing the attributes of electricity markets relevant to investment decisions, it is worthwhile to review the physical nature of electricity supply and to identify the components under investigation.

Electricity supply is commonly divided into three functions: generation, transmission, and distribution. Power retailing is sometimes listed as a separate fourth function. Very briefly, generation involves the conversion of energy from one form, frequently chemical energy in the form of fossil fuels, into electrical energy. This process typically occurs at centralized power plants. The electrical energy is transported through high voltage transmission lines to load centers, where it is distributed by the local power company. Traditional retailing services include metering and billing for electricity services. Restructuring initiatives are affecting, to a greater or lesser extent, the organization of all four supply functions, but this thesis focuses solely on electricity generation.

Two peculiarities of electricity supply are important to note. First, electricity cannot be stored economically on a large scale, and second, electricity demand exhibits significant seasonal and hourly variation, and smaller instantaneous fluctuations. Satisfying demand in a region at peak hours therefore requires that some generating capacity will remain idle most of the time. *Capacity factor* is a measure of a unit's output over a period of time as a fraction of the output that would be generated if the unit ran at rated capacity over the entire period. The capacity factor predicted over the life of a generating asset has a significant effect on the asset's valuation. Plant dispatch and capacity factor will be discussed more in the next chapter.

2.1 Traditional electric power industry structure

The traditional business model for electricity production in the U.S. is that of a regulated vertically-integrated investor-owned utility (IOU). These firms own generation, transmission, and distribution assets within a geographic region and hold exclusive rights to serve retail consumers in the franchise area. In return for monopoly protection, state public utility commissions dictate service obligations and set electricity prices to ensure that IOUs do not extract excessive rents from consumers. The following summary of the regulated industry model draws from Joskow (2000, 1996) and Joskow and Schmalensee (1983).

The electricity supply industry developed in the form of vertically-integrated utilities with government-sanctioned regional monopolies in part because these firms have natural monopoly characteristics. A natural monopoly arises in industries where the total market cost of production is minimized by the existence of a single firm supplying the entire market. Industries with natural monopolies often are characterized by some combination of economies of scale, economies of scope, and economies of vertical integration. The electricity supply system exhibits a number of these features.

Electricity distribution requires physical connections in the form of power lines from the distribution center to all end consumers. Running multiple sets of wires to each household is impractical and would increase the cost of service. Transmission systems exhibit similar economies of scale, but more importantly, they provide a variety of system services that benefit from close coordination and control. The system must respond rapidly to changes in system load and unplanned transmission and generation outages. A central system operator with control over a geographically expansive transmission system is more equipped to meet the real-time management demands of the system than would be multiple operators coordinating through market transactions. System management also requires close integration of transmission and generation assets as generating resources are called upon to adjust output levels to match demand and maintain power quality on the network.

Taking a long-term perspective, coordinated planning of new investment can lead to economically efficient system topology, as new generating stations are located and transmission lines are upgraded in a way that reduces the delivered cost of electricity. This is not to say that multiple firms are unable to coordinate their investment activities, or cooperate to provide real-time system control during operation, but simply that these functions require a certain level of integration through organizational arrangements, market forces, or governance structures.

The nature of electricity demand suggests that economies can be achieved by increasing the number of customers. Because electricity is supplied in real-time and customers' demands are not perfectly correlated, having more customers means, all else equal, that less capacity is required per customer, simply because at any given time some customers will demand less than their maximum load. Finally, electricity generation exhibits some economies of scale at the unit, plant, and firm level, in the form of construction and operating efficiencies.

The industrial structure that emerges from these characteristics depends on the magnitude and scale of the economies and on the ability of different market and organizational arrangements to perform the coordinating function. For instance, economies of scale at the generating unit or plant level may exist, but they have no consequence for the formation of vertically-integrated utilities. An important example of inter-firm coordination has developed in the form of power pools where utilities cooperate to achieve additional economies of scale. The vertical integration of generation, transmission, and distribution into regional utilities developed in part because the combination of these functions under one controlling organization was viewed as the most feasible and efficient approach to achieving the economies listed above. Whereas local distribution and regional transmission have the characteristics of natural monopoly, the monopoly organization of electricity generation can be explained not independently but through its interconnections with the transmission system.

If a monopoly emerges and is seen as the most efficient way to serve a market, as in the case of the electric power industry, public regulation of prices is applied to prevent inefficiencies that would likely arise from monopoly pricing behavior. Because electricity is a public good, regulators also defined service obligations and monitored the investments and financial health of utilities. Retail prices were set using cost-of-service ratemaking principles that allowed a utility to pass the costs of operating the plant, including capital depreciation, through to consumers, and to receive a fair rate of return on its undepreciated capital stock, which comprised the *rate base*. Costs and investments deemed not to be prudent were frequently excluded from the rate determination process and were not allowed to be passed on to consumers or added to the rate base, in contrast to strict cost-of-service regulation (Joskow, 2000).[1]

The expectation of electricity rates set to allow capital recovery of investments in generating units meant that large capital projects were not necessarily high-risk investments for IOUs. A significant fraction of the risks associated with uncertainties about construction costs, operating costs, operating performance and general supply and demand conditions involving investments in generation projects were shifted to the consumers through the regulated retail electricity prices they paid. For example, if a new generating project's construction costs exceeded those for comparable projects, investors would not bear the full burden of the additional costs. Instead, some of the additional costs would be passed through to consumers through the regulatory process. Similarly, if a new generating project's costs were less than those of comparable projects, investors did not see a higher return commensurate with a less costly project. Instead, consumers got the benefits of this good performance through lower regulated electricity rates.

[1] This was the situation with a number of nuclear projects in the U.S. As construction and operating costs of nuclear plants exceeded projections, some costs were allowed to be passed on to consumers while other costs were absorbed by the utilities, leading to utility insolvency and high electricity rates to recover sunk costs.

Regulatory lag and the ability of regulatory agencies to disallow unreasonable costs exposed investors to some performance and market risks, but much less than if they were unregulated and had to compete in competitive markets.

It is generally thought that by insulating regulated firms from most of the performance and market risks associated with their investment decisions that their incentives to control construction costs and to operate their plants well would be diminished and their customers would be required to pay for excessive construction and operating costs. As discussed below, competitive wholesale markets shift the bulk of these risks back to the project's investors. If this were all that competitive wholesale markets accomplished, the costs of capital faced by investors would rise and the average cost of electricity faced by consumers would rise as well to reflect these higher costs. However, the primary idea motivating wholesale market competition is to give investors in generating plants high powered incentives to reduce construction and operating costs, to improve operating performance (e.g. plant availability), and to choose technologies that reflect their inherent performance and market risks. The cost savings associated with better performance in these dimensions is thought by proponents of competition to be greater than the increased financing costs investors must incur as a result of increased performance and market risks that they must bear. In this case, consumers benefit in the long run as the overall cost of supplying electricity falls.

2.2 Competitive wholesale markets and merchant power plants

The movement toward competitive markets for electricity in the U.S. can be traced back to 1978 and the passage of the Public Utility Regulatory Policy Act (PURPA). PURPA was an attempt to encourage improvements in energy efficiency by requiring utilities to purchase power produced by a new class of generating entities. These Qualifying Facilities (QF) were primarily cogeneration sources and plants using renewable fuels. While in many cases the utilities' obligations to purchase power from QFs increased the utilities' total cost of service for years to come, PURPA had the indirect effect of proliferating the belief that generation services could be decoupled from the regulated transmission and distribution functions of IOUs (Joskow, 2000). This led in the 1980s to pressures on the Federal Energy Regulatory Commission (FERC) to remove barriers to expanded development of independent generating sources from non-QF sources. Joskow (2000) provides a detailed account of the legislative, regulatory, and industrial developments from PURPA through the state deregulation initiatives of the late 1990s. A brief mention of the important developments, drawn from that article, is provided here.

FERC, in the late 1980s, began taking steps to increase competitive opportunities for independent power producers (IPP) other the QFs. Federal price regulations on interstate sales were removed, allowing new entrants to benefit from market-based pricing, and FERC began promoting the goal of open access to transmission services so that IPPs could sell power to utilities other than the local utility. FERC was limited by statute in its ability to force open access to transmission services until Congress passed the Energy Policy Act of 1992 (EPAct92), which among other things, expanded FERC's authority in this area. After EPAct92, and through a series of FERC Orders[2], utilities were increasingly required to offer a host of transmission services at fair cost-of-service rates, provide public information on pricing and capacity, accommodate reasonable proposals to expand the transmission system to serve new generating facilities, and generally to forego any advantages provided by its own vertical integration of transmission and generation assets.

In the 1990s, a new model of the electric power industry began to gain interest whereby all competitive services, including generation and retail marketing, would be fully separated from the natural monopolies of transmission and distribution. This new model gained momentum at the state level, particularly in states where regulated electricity prices substantially exceeded wholesale market rates, often due to unforeseen costs of nuclear projects and long-term contracts to purchase power from QFs at rates well above

[2] FERC Order 888 and Order 889 were particularly instrumental in promulgating open access rules for transmission services.

current market rates. While a number of issues required resolution before full wholesale and retail competition could be achieved, most notably provisions for utilities to recover stranded costs due to previous investments and commitments, state restructuring initiatives have effected a number of important structural changes that are likely to persist and spread to other states as the new industry model, or at least wholesale competition, gains acceptance. These include the emergence of merchant power plants, the creation of wholesale spot and forward markets for power and auxiliary network services, and the transfer of control of the transmission system from the utilities that own the assets to non-profit or independent organizations that provide fair and open access.

A merchant power plant sells it output into the power markets, taking on the market price risk. When market prices are high, substantial profits may accrue. If electricity market prices are low, production costs are too high, or the plant suffers from poor performance and thus low availability, the plant may not generate enough revenues to recover fixed capital costs.[3] To reduce market risk, plant owners can enter into bilateral supply contracts of various durations and trade in energy futures markets to hedge against future price volatility. Futures market participation may also reduce fuel price risks that are especially important for new combined cycle plants. Project development risks, in the form of cost overruns during plant construction due to construction delays or increased labor and material costs, are also borne by the merchant plant owner, unless they can be shifted to the architect-engineer or component vendors through fixed-price contracts.

[3] Unlike regulated utilities, merchant plants have no obligation to serve consumers. Therefore, if market prices drop below marginal production costs, properly accounting for the cost to suspend and restart operations, a merchant plant will cease production. In certain circumstances, such as periods of volatile fuel prices, this freedom could be a valuable option.

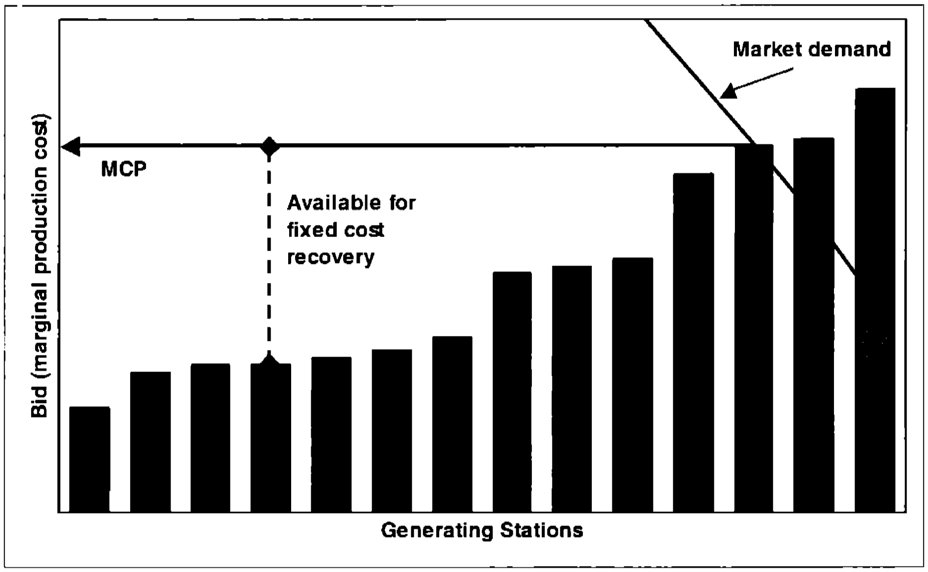

Figure 2-1: Determination of wholesale electricity market clearing price (MCP)

In the spot electricity market, or day-ahead market, producers participate in an auction run by a power exchange that determines how much electricity each plant will supply for each hour. Bids are aggregated and matched to a demand curve to determine the hourly market clearing price (MCP) (Skantze and Ilic, 2001). All bids below the clearing price are accepted and are paid the clearing price. Merchant plants must be able to produce below the market clearing price in order to recover fixed capital and operating costs, as illustrated in Figure 2-1. Therefore, the prospects for profitability of capital-intensive investments depend not only on the plant's ability to produce cheaply, but also on the production cost of the marginal supplier. In times of peak demand, when the supply system is physically unable to increase production, the competitive price required to match supply and demand will be often much higher than the marginal production cost of the incremental producer. In this case, scarcity rents, or the difference between the MCP and the marginal production cost of the last increment of generation, will accrue to all producers. These scarcity rents can constitute a substantial portion of the net revenues necessary for capital cost recovery, especially for peaking units (Joskow, 2003). Merchant developers must be mindful of the regional composition of generating assets, including future projects, and the potential for scarcity rents when considering a new project,[4] without the benefit of integrated resource planning made possible by a single utility serving an entire market.

[4] Spot markets are also vulnerable to the exercise of local market power which can drive up spot rates. FERC and independent system operators have employed a variety of mechanisms to prevent uncompetitive behavior (Joskow, 2003).

3 Electricity Generation Technology Characteristics

Before discussing valuation methods for power plant investments, it is important to identify and understand the relevant characteristics of the technology options available for electricity generation. This chapter summarizes the primary physical features of generation technologies that determine their lifecycle costs and relative attractiveness from an investment standpoint. The technologies most likely to be deployed for base load generation, as defined below, are then introduced with primary focus on the features affecting investment decisions. The analysis focuses solely on plants being evaluated for operation as base load facilities with high lifetime capacity factors to allow for a fair comparison of total lifecycle costs.

As noted above, the electricity supply network must respond in real-time to changes in system load. Demand exhibits predictable seasonal and hourly variation due to regional climate and consumers' daily routines respectively, and less predictable variation due to extreme weather events, business cycles, and regular consumer activity. In addition to matching demand, the electricity supply system must have sufficient reserves to cover planned and unplanned equipment outages.[5] Satisfying consumer demand and maintaining system reliability in times of peak demand requires that during most of the year, quite a bit of generating capacity will be sitting idle. The frequency distribution of electricity demand is often displayed as a *load duration curve*, which is a plot of system load in decreasing order as a function of duration, over some time period. The sample load duration curve in Figure 3-1 clearly shows the inevitability of idle capacity.

[5] Reserves are also required during system operation for voltage regulation and to match unpredicted load. The grid operator attains these ancillary services through auctions similar to those for electricity supply.

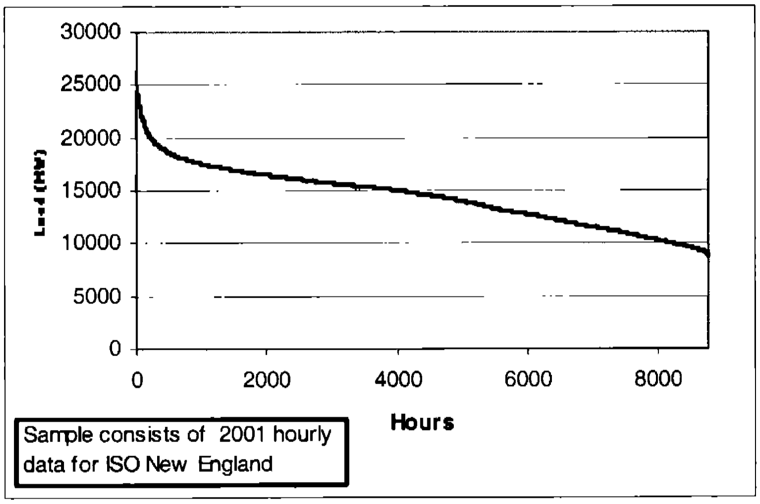

Figure 3-1: Sample load duration curve

Generating stations are commonly grouped into three categories based on the times that they are expected to be dispatched: base load, intermediate load, and peaking capacity. Base load plants are designed to run almost continuously, net of maintenance downtime, and therefore the total base load capacity in a region should correspond roughly to the off-peak load. Technologies with low marginal production costs, such as nuclear and hydroelectric power, are prime candidates. Intermediate load plants cover daily fluctuations and peaking units operate during times of maximum demand, typically only a small fraction of the time. Technologies with high capital costs, such as nuclear power, are not deployed as intermediate or peaking capacity because, besides technical limitations preventing repeated shut-down and ramp-up of production, the revenues received during peak- or intermediate-load hours alone are insufficient to recover the large initial capital expenditure. These distinctions are necessarily crude since there is a continuum of load factors required to match an annual load duration curve.

3.1 Power plant characteristics relevant to investment decisions

The U.S. Energy Information Administration (EIA) predicts that from 2001 to 2025, 428 gigawatts (GW) of new generating capacity will be needed to meet U.S. demand growth and to replace retired plants, slightly more than half the existing stock (EIA, 2003). The EIA report also indicates that 95% of the 144 GW of new capacity added to the grid between 1999 and 2002 consists of natural-gas-fired units.[6] To understand why natural gas currently is the fuel of choice, and in order to forecast future changes in the mix of generation technologies, one must consider the features of power plant construction and operation that affect cost most directly. The primary features are summarized below.

Capital cost and construction time

Electric power generation at a centralized power plant requires a large initial investment in capital equipment. For some technologies, the capital investment is the single largest cost component over the life of the unit and must be recovered over decades of operation. For instance, EIA estimates that capital costs will account for nearly 80% of the levelized cost of electricity generation from future nuclear plants (EIA, 2003). Due in part to economies of scale, units can be 1,000 MW or larger, requiring an initial investment of over one billion dollars. In such cases, the financing charges are considerable, especially if it is perceived to be a risky venture.

Closely coupled to capital cost is the time required to build a power plant. Large base load plants commonly take four years or more to build, and the last batch of nuclear plants in the U.S. took much longer. Long construction and regulatory delays after capital has been invested in the plant can be detrimental to project value, especially for projects with a high opportunity cost of capital. Additionally, a long construction period increases the likelihood that the market environment that justified the investment will no longer exist by the time the plant is ready for commercial service. Clearly, there is a competitive advantage for technologies, such as combined-cycle gas turbine technology, with relatively short construction times.

[6] Of the 138 GW of new natural-gas-fired capacity, 72 GW were combined-cycle plants and 66 GW were combustion turbines (EIA, 2003).

Volatility of fuel prices

The reason that technologies with high capital costs are considered for base load generation is that they tend to have relatively low and stable fuel costs. Besides capital costs, lifecycle generating costs (ignoring transmission and distribution) are frequently classified as either operating and maintenance (O&M) costs or fuel costs. For a natural gas-fired combined cycle plant, fuel costs may account for more than half of the total cost of the plant. In periods of high volatility or escalating prices in natural gas markets, the marginal production costs for gas-fired generation will be similarly affected.

Economic lifetime

Generating units are built to produce electricity for decades. For units with high capital costs, consistent operation over many decades is the only means of recovering the initial investment. On the other hand, maintenance costs and incremental capital expenditures tend to increase as the unit ages. For example, many operating nuclear plants in the U.S. have applied or are considering applying for operating license extensions from the Nuclear Regulatory Commission (NRC) because of the belief that the plants can continue to produce at low cost with fully-depreciated capital. Not long ago, many nuclear plant owners were contemplating retiring plants early to avoid large capital expenditures such as steam generator replacement. Care must be taken when considering the economic lifetime of a unit for valuation purposes. The operational life of a merchant plant often extends well beyond the investment horizon and out-year revenues will be ignored or heavily discounted when the investment decision is made.

Environmental factors

All generating technologies have some adverse impacts on the natural environment. From the perspective of the investor, only those impacts that are, or are likely in the future to be, internalized into the cost of generation need to be considered in the valuation. For some technologies, environmental costs are already significant contributors to overall cost. New coal plants must meet a strict set of environmental standards to limit air pollutant emissions, nuclear plants must contribute to a fund for final waste disposal, and wind power enjoys a government subsidy – a negative cost – because of its status as a clean and renewable source of energy.

One environmental concern that is not presently internalized but may be an important factor in the near future is the threat of global climate change, attributed in part to emissions of carbon dioxide. All fossil fuel technologies emit carbon dioxide, though not in equal amounts on a per kilowatt-hour (kWh) basis. If the U.S. and other countries regulate or tax carbon emissions from electricity generation, the relative competitiveness of generation technologies could shift significantly. Such regulatory action is conceivable enough that it should at least increase the perceived risk of new investments in fossil fuel technologies.

Flexibility

A final characteristic of generating technologies is their inherent flexibility in the face of uncertain costs and market conditions. This is likely to be more significant in a merchant environment than for a regulated utility that has a captive customer base and can pass operating costs through to consumers. As an industry, power generation is relatively inflexible in that the large capital invested cannot easily be converted to other uses. Combined cycle technology brings some flexibility to base load generation through smaller unit size, shorter construction time, the ability to run competitively at lower utilization, and the possibility of fuel switching when natural gas prices are high. The discussion of flexibility and how it is valued is deferred until Chapter 6.

3.2 Base load generation technologies

This section briefly describes the primary technology options for future base load generation. Combined cycle technology has the ability to operate economically at lower capacity factors but is being treated as a base load option in the present analysis. The technologies evaluated are nuclear, pulverized coal, and natural gas-fired combined cycle plants. Within each primary fuel type classification exist numerous designs and classes of technology, but for the purpose of this study, one characteristic design for each fuel type is selected. Cost and performance parameters are selected to be representative of mature technologies (with no first-time engineering costs) in the 2005-2010 timeframe, and are not meant to definitively characterize the technologies, but to provide a basis to assess economic valuation methods and the impact of new market conditions.

Nuclear power

Nuclear power has a brief, yet troubled history. Beginning in the 1950's, proponents claimed that the new technology would produce electricity for a fraction of the cost of fossil plants. In many cases, the opposite has become true. Nuclear projects have been plagued by cost overruns, delays caused by construction quality problems, regulatory adjustments, and citizen intervention, and higher than expected operating costs[7]. Some industry participants are convinced that the next generation of nuclear plants, if given a chance, will be able to overcome these past difficulties and produce electricity at competitive rates.

The attributes used in the analysis are representative of advanced light water reactors (ALWR) available in the 2010 timeframe. Capital cost estimates are necessarily uncertain, since none have been built in the U.S., but recent overseas experience and

[7] EIA (1986) provides an historical account of the discrepancies between actual construction costs and lead times for nuclear plants in the U.S. and the costs and lead times that were projected by the utilities prior to construction. PIU (2001) provides a brief account of similar experiences in the U.K.

reasonable analysis suggest overnight capital costs could be in the range of \$2,000 / kW[8] in 2003 dollars and the units could require four to five years to construct. It should be noted that under regulation, if nuclear construction costs exceeded initial estimates, which they frequently did, the utilities would argue with the regulatory commission over how much of the cost overruns would be passed on to consumers. In a competitive market, there is no such opportunity. Merchant plant owners receive market price for electricity. Any cost overruns or underruns will affect the firm's profits, not the price of electricity.

The construction time for new nuclear plants, already long compared to combined cycle plants, is highly uncertain due to the prospect of continued delays from new regulatory procedures, intervenors determined to prevent nuclear development, and the challenge of securing skilled labor. Nuclear units are typically on the order of 1,000 MW and therefore require a substantial initial investment. The opportunity cost of capital is likely to be higher than that for fossil plants due to the greater perceived financial risk, including the longer lead time. Designers of future generation reactors are addressing this problem with smaller and modular reactors.

Nuclear operating costs have decreased in recent years and remain low and stable compared to fossil plant costs, contributing to the recent trend of operating license extension applications for an additional 20 years. Presumably, plant owners expect that maintenance costs and capital replacement costs will not escalate enough to make continued operation uncompetitive, or at least that the uncertainty in future electricity markets makes the option of extended operation worthwhile. Some new designs specify a projected operating life of 60 years, as opposed to the traditional 40 years.

On the environmental issue, the perception of nuclear plant performance is mixed. Many environmental groups oppose nuclear power due to concerns over the disposition of

[8] Detailed engineering cost calculations by nuclear vendors have produced estimates of \$1,500 / kW and lower. The effect that this capital cost reduction has on the investment decisions will be analyzed below.

radioactive waste and the potential for an ecological and human health disaster in the unlikely event of a full-scale nuclear accident. Both social costs are internalized to an extent, through the mandatory nuclear waste fee and mandatory redundancy in safety systems. Proponents point to the negligible emission of air pollutants and carbon dioxide, and in fact, the lack of carbon dioxide emissions has become a prime rationale for renewed focus on nuclear power. Government actions intended to curb carbon emissions could be a boon for nuclear power, if it is awarded credit for its carbon-free status. The cost and performance parameters used in the economic analysis are listed in Table 3-1.

Coal steam power

Coal-fired power plants supply the largest percentage of base load generation in the U.S. The cost attributes used in the analysis are representative of a subcritical pulverized coal (PC) plant feeding a conventional steam turbine and complying with Federal New Source Performance Standards (NSPS) for air quality. Supercritical plants and new technologies such as fluidized bed designs and coal gasification plants will have different cost attributes.

Overnight capital costs are estimated at $1,350 / kW in 2003 dollars when including all environmental compliance equipment. A nominal construction time of four years is assumed, making coal less capital intensive than nuclear, but still requiring a substantial investment for a typical plant capacity of 500 to 1,300 MW. Coal plants are designed for long operating lifetimes, operating costs are stable, and domestic coal supplies are abundant. Compliance with NSPS internalizes much of the environmental costs, but carbon dioxide emissions regulation remains as potentially a large new source of production cost. Coal is more carbon intensive than natural gas and pulverized coal plants with steam turbines burn fuel less efficiently than combined cycle technology, meaning that carbon emissions per kWh produced are significantly higher[9]. Any regulatory program that places a price on carbon emissions – e.g., a carbon emissions tax or a carbon cap and trade system – would make coal technology less competitive compared to other fuel sources.

Strategies for dealing with carbon emissions from coal plants are being investigated as possible contributors to future carbon emissions reductions. So called carbon capture and sequestration processes remove carbon dioxide from the exhaust stream and direct it to non-atmospheric sinks, which can be depleted oil and gas reservoirs, unmineable coal seams, deep saline formations, or deep in the ocean.[10] New technologies for generating electricity from coal, specifically integrated coal gasification combined cycle (IGCC) plants promise not only higher thermodynamic efficiencies, reducing carbon emissions per kWh, but also new pre-combustion and combustion processes that make carbon capture more economical. IGCC plants are not addressed in this analysis. Table 3-1 contains the cost and performance parameters for pulverized coal technology.

Combined cycle gas turbines

Combined cycle gas turbine (CCGT) plants consist of one or more gas turbine generators equipped with heat recovery steam generators that use exhaust heat from the turbines to raise steam, which produces additional power in a steam turbine. This technology has drawn natural gas into the base load market and most new capacity being installed today consists of CCGT units. Overnight capital costs are $550 - $650 / kW in 2003 dollars and a plant can be built in two to three years, requiring much less capital than coal or nuclear plants. Larger CCGT plants use multiple gas turbines for capacities above 500 MW and are frequently assumed to have shorter operational lives than coal or nuclear plants. CCGT cost and performance parameters are listed in Table 3-1.

[9] Based on the assumptions provided in Table 3-1 for heat rates and carbon coefficients, coal plants emit 226 kg-C/MWh, compared to 93 kg-C/MWh for CCGT plants, a factor of 2.4 times higher.
[10] Howard Herzog at MIT has done considerable work in the area of carbon capture and sequestration. A description of his research is available at http://sequestration.mit.edu.

The major cost driver in CCGT plants is the cost of natural gas. Growing demand and projected shortfalls in North American production have led to some speculation that long-term prices will settle well above historical prices. In its latest outlook, EIA forecasts prices above $4 / MCF (thousand cubic feet) over much of the next 20 years (EIA, 2003). If electricity markets continue to clear with conventional steam turbines using burning natural gas and oil and (during the highest demand conditions) single cycle gas turbines burning natural gas, then combined cycle plants will produce below the clearing price regardless of the price of natural gas because of their higher thermodynamic efficiency as compared to conventional steam turbines and single cycle gas turbines. This suggests that the occurrence of volatile or escalating natural gas prices does not in itself imply that profits from combined cycle plants will exhibit the same level of volatility in areas with a large existing fleet of gas-fired steam turbines and gas turbine peaking capacity (MIT, 2003).

CCGT has an advantage over pulverized coal plants in environmental cost, as natural gas burns much cleaner than coal and is less carbon intensive, and the plants run at much higher thermodynamic efficiencies (approaching 60% for CCGT compared to 35% for pulverized coal plants). A potentially large advantage of CCGT is its flexibility. Plants can be built quicker and with smaller capacity to match various market conditions, can operate economically at lower capacity factors due to smaller capital recovery requirements, and, in situations where natural gas prices are high for an extended period, the technology can be adjusted to burn other petroleum products. The value of this inherent flexibility of design is discussed only briefly in Chapter 6.

Table 3-1: Representative cost and performance characteristics for base load technologies

(2003 $)	Units	Nuclear	PC	CCGT
Capital Investment				
- Net rated capacity	MW	1,000	1,000	600
- Overnight cost	$/kW	$2,000*	$1,350	$600
- Construction period	years	5	4	2
- Design life	years	40*	40*	25*
- Incremental capital exp.[1]	$/kW-yr	18	16	6
- Decommissioning cost[3]	$mm	450	-	-
Operations				
- Fixed O&M – base year[1]	$/kW-yr	58.5	24.5	10.2
- Variable O&M – base year[1]	mills/kWh	0.4	3.1	2.0
- Real O&M escalation	%	0%	0%	0%
- Fuel cost – base year[1]	$/mmBTU	$0.40	$1.20	$4.00*
- Real fuel escalation	%	0%	0%	0.5%*
- Heat rate[1]	BTU/kWh	10,400	8,700	6,400
- Nuclear waste fee	mills/kWh	1.0	-	-
- Carbon coefficient[2]	kg-C/mmBTU	-	26.0	14.5

1. EIA, 2003.
2. EIA, 2002.
3. NRC website (http://www.nrc.gov/reactors/decommissioning/funding.html, accessed 7/15/2003.

* Parameters in the sensitivity analysis.

4 Investment Decisions for Regulated Utilities

Chapter 2 discusses the role of the investor-owned utility (IOU) in electricity generation. IOUs are given exclusive rights to supply electricity in a region at prices determined by government regulators. The revenue requirement method is commonly used in the electric utility industry for economic evaluation of alternative investments, including investments in generating resources. This chapter begins with a discussion of utility investment valuation using the revenue requirement method. The method is then applied in a case study of alternative base load generation technologies and results are presented that identify conditions under which investments in nuclear power would be forthcoming in a regulated utility industry. These results are used in Chapter 5 as a baseline for evaluating the effect that industry restructuring will have on nuclear investment.

4.1 Revenue requirement method

The revenue requirement is defined as the total amount of revenue that is required to compensate a utility for all expenditures associated with the construction and operation of a power plant (EPRI, 1986). Electricity rates were set by regulators at a level that just allowed the utility to recover its operating expenses and capital carrying charges through sales of electricity, providing the utility with zero economic profit. Carrying charges included the returns to investors, income taxes, book depreciation, and property taxes and insurance (PTI). This type of economic regulation is referred to as cost-of-service regulation and was an attempt to force competitive prices in an uncompetitive market.

To calculate the capital carrying charges, the regulator determined the *rate base* of the utility and the return that would be allowed on the rate base. The rate base is the value on which the utility's investors are allowed to earn a return, and is roughly equal to the value of undepreciated assets, with some adjustment for disallowed expenditures. Using standard cost accounting formulas for depreciation and retirement of debt and equity, the regulator set the return on the rate base to cover the utility's costs of financing capital projects necessary to meet the region's electricity demand.

Cost-of-service regulation lends itself to a simple valuation technique, referred to as the revenue requirement method. When considering new investment in a power plant, the expected costs associated with the plant can be forecast. The costs are discounted to present value, using the after-tax weighted-average cost of capital (WACC) discussed below, and then annualized to determine the real levelized cost of generation, or the levelized revenue requirement for the new investment. This real levelized cost provides an indication of the price of electricity that the regulator will have to allow over the life of the plant so that revenues are sufficient to cover all costs associated with construction, financing, and operation of the plant. The revenue requirement method to power plant valuation is encapsulated in the simple cost model described in Appendix B, which will be called the RR model. Before presenting results for the case study, further discussion of the levelized cost calculation and discounted cash flow analysis is warranted.

4.2 Levelized costs and discounted cash flow analysis

The revenue requirement method is a manifestation of discounted cash flow analysis, the standard procedure for determining the value of an investment. In general terms, discounted cash flow analysis begins by estimating all future cash flows associated with an investment or project. The future cash flows are discounted to present value, that is, their equivalent value today is determined taking into account the time value of money, and accumulated to find the net present value (NPV) of the investment. The choice of discount rate is discussed below. The NPV rule, ubiquitous in corporate finance texts, states that any investment with a positive NPV is a good investment and should be pursued. In the case of two or more mutually exclusive investment opportunities, the choice with the highest NPV is optimal. This comparative analysis requires some care in defining the bounds of an investment, especially investments with different time horizons, but it provides the means for selecting between alternate investments. In

Chapter 6, a refinement to the classic NPV rule is briefly discussed that incorporates the flexibility to delay expenditures while pursuing an investment strategy.

The revenue requirement method reverses the procedure. Given the goal of zero economic profit, represented by an NPV equal to zero, the required annual revenues are determined so that the present value of all revenues exactly balances the present value of all project costs. When operating costs are expected to escalate, the actual revenue requirement for the utility in each year will increase to cover the higher operating costs. Instead of comparing alternate investments by looking at the revenue requirement in each year, a constant revenue level is determined such that if electricity prices were set at that level over the entire life of the project, the goal of zero economic profit would be met. This constant revenue level is called the levelized cost because its value is based entirely on the project's costs. If it is constant in current-year dollars, that is, it doesn't increase with inflation, then it is called the nominal levelized cost. If it is constant in inflation-adjusted dollars, it is called the real levelized cost. The choice of real vs. nominal levelized cost affects the choice of discount rate, which is discussed next.

4.3 Weighted-average cost of capital

The levelized cost calculation requires that future cash flows be discounted at an appropriate discount rate. For a regulated utility, the appropriate rate is the utility's weighted-average cost of capital (WACC). Using a firm's WACC to discount project cash flows implicitly makes certain assumptions that are applicable to regulated utilities and are consistent with the assumptions made by regulators when determining the return that a utility will be allowed on its rate base. The derivation of the WACC follows.

Companies finance capital projects through a variety of sources, which can be classified simply as debt or equity. Debt financing involves borrowing money, often through the issuance of corporate bonds, with an obligation to repay the principal at a specified time and to make periodic interest payments at a pre-determined rate, providing the lender a fixed return in the absence of default[11]. Debt issues can vary in maturity, seniority, and repayment provisions, and can be secured with physical assets or supported by future cash flows of the company or project. A multitude of corporate finance texts are available that discuss debt financing in greater detail, including Brealey and Myers (2003). Equity refers to the company's ownership. Financing capital projects by issuing new common stock or through retained earnings is considered equity financing. In general, the cost of equity, or the expected return on equity, to the firm is greater than the cost of debt because the equity holder shares more in the risk of the project. Equity investors benefit if profits exceed expectations, but may receive low or negative returns if the project underperforms. Not all financing mechanisms fit perfectly into this binary classification but it is sufficient for the discussion at hand.

Nearly all companies have a combination of outstanding debt and equity ownership. If the costs to the firm of debt and equity financing, weighted by total value, can be combined into a single cost of capital, then investment decisions can be evaluated independently of financing considerations. The company's nominal cost of capital is calculated by taking the average of the expected returns on debt and equity, weighted by value (Brealey and Myers, 2003).

$$\text{Company nominal cost of capital} = \frac{D}{V} r_D + \frac{E}{V} r_E$$

This expression captures the expectations of investors but ignores the tax deductibility of interest payments on debt. Tax deductibility of interest effectively makes debt cheaper for the company by a factor equal to the corporate income tax rate. (The marginal income tax rate is used for evaluating new investments.) To maintain the separation of financing decisions from capital investment decisions, this tax shield must be included in the discount rate that reflects the cost of financing. This is achieved by estimating the

[11] Bonds typically offer fixed coupon payments in current-year dollars. When the rate of inflation varies, the real return on the debt security varies inversely with inflation, but the nominal return remains fixed.

after-tax cash flows for an unlevered project (assuming no debt financing), and then discounting using an adjusted cost of capital that captures the tax shield provided by debt. The expression for the nominal after-tax weighted average cost of capital is:

$$WACC = r = \frac{D}{V} r_D (1 - \tau) + \frac{E}{V} r_E$$

When using a company's WACC to discount after-tax project cash flows, all financing details can be set aside because they are incorporated in the discount rate. This is a simple and commonly used valuation approach, but it makes certain assumptions that may introduce large errors if not properly considered. First, using the firm's WACC assumes that the project under investigation is no more or less risky than the firm's existing business. If it were, then the cost of capital does not apply to the new project. If a project is financially distinct from its parent company, then a cost of capital that is representative of the financing options for the independent project should be determined for proper valuation. Second, use of the WACC assumes that the project does not have an enduring effect on the capital structure, or relative weights of debt and equity, of the firm. Increased leverage would put shareholders' future cash flows at higher risk, which would increase the cost of equity. This implies also that the capital structure remains constant over the life of the project.

Discounted cash flow analysis using the firm's WACC was well suited to utility investment valuation. Regulators assumed that debt was paid down in proportion to plant depreciation so that the debt/equity ratio remained constant until the plant was fully depreciated for regulatory purposes. Regulators also assumed that the project debt/equity ratio was equal to the firm's overall debt/equity ratio. In reality, regulated utilities tended to have large capital asset bases and relatively constant debt/equity ratios. The risks associated with a new project were likely to be similar to the overall risk of the utility for two reasons. First, the new generating resource would be serving the same geographic market, the utility's franchise area, with the same product, electric power, that existing resources did. (Base load, intermediate load, and peaking capacity could be seen as serving different markets, but even in this case, the utility must maintain a balance of each type of capacity. Base load generation only is being considered in the present analysis, so this is not an issue.) Second, cost-of-service regulation allowed operating costs to be passed through to consumers and provided a fair rate of return to investors, moderating the investment risk that an unregulated developer would face. The regulatory commission had the prerogative to disallow imprudent expenditures but major capacity additions required prior approval, which offered investors some assurance of returns. For these reasons, discounting after-tax cash flows using the utility's WACC is an appropriate method for valuing the investment opportunities of a regulated utility.

If cash flow are expressed in constant, or inflated-adjusted, dollars, then the nominal WACC as defined above is not applicable. In this case, a real discount rate is required. Briefly, a nominal rate and a real rate are related by the following identities:

$$1 + r = (1 + e_i)(1 + r')$$

$$r' = \frac{r - e_i}{1 + e_i}$$

The expression for the real WACC is then:

$$\text{Real WACC} = r' = \frac{D}{V}\left(\frac{r_D(1-\tau) - e_i}{1 + e_i}\right) + \frac{E}{V}\left(\frac{r_E - e}{1 + e_i}\right)$$

Note that the real WACC is not simply the weighted average of the real rates of return on debt and equity, because the interest tax shield remains a percentage of the nominal interest rate, not the real interest rate. Constant-dollar analysis using the revenue requirement method produces a real levelized cost, which is preferable for economic comparisons of alternatives. The real levelized cost more accurately reflects the true economic value of investments and provides more insight into real cost trends. Utilities tended to favor current dollar analysis because the numerical values of estimated costs more closely approximated actual expenditures and values that would appear in company financial statements (EPRI, 1986). In fact, as long as the economic lives of all options are of equal duration, the relative ranking of options will be the same regardless of whether the real or nominal levelized cost is used. The case study that follows uses real levelized costs for comparisons of generating technology alternatives.

4.4 Regulated utility investment valuation

Before calculating real levelized costs for the base load technologies under consideration in this analysis, a set of financial parameters that are representative of regulated utilities must be defined. Specifically, computing the firm's real weighted-average cost of capital depends on the interest rate on debt, the required after-tax return to investors, the capital structure, or debt ratio, and the corporate income tax rate, and the assumed rate of general price inflation. The financial assumptions for utilities in this analysis are presented in Table 4-1.

Table 4-1: Financial parameters representative of a regulated utility

4.4.1. Parameter	Value
Nominal interest rate	**7.5%**
Nominal after-tax return on equity	**11.5%**
General rate of price inflation	**3%**
Debt ratio (D/V)	**60%**
Corporate income tax rate	**38%**
Economic life of plant	**30 years**
Nominal WACC	**7.4%**
Real WACC	**4.3%**

The parameter values are not meant to be definitive for any given utility, but are chosen to be indicative of utility financing and to elucidate the difference between utility and merchant plant investment costs. The real rates of return are compatible with recommended values in the fifth revision of the Electric Power Research Institute's Technical Assessment Guide (TAG™) (EPRI, 1986) and are not inconsistent with historical returns on utility stocks and bonds. (A compilation of historical financial performance of utility stocks and bonds is provided in Hyman et al, 2000.) An economic life of 30 years was chosen because it is often cited as the standard value for analysis of power plant investments (EPRI, 1987).

Comparison of generation alternatives

Using the RR model in Appendix B, real levelized costs were calculated for nuclear, pulverized coal (PC), and combined cycle gas turbine (CCGT) base load plants under a variety of assumptions. The results provide an indication of the conditions under which nuclear power would be selected to provide new base load capacity for a regulated utility.

The baseline cost and performance parameters for the three technologies were listed in Table 3-1. Some values were taken from standard sources, such as the Energy Information Administration, and others are assumptions or estimates based on a review of available data. What is important is that the values are roughly representative so that differences in valuation methodology and market environment can be identified. Some costs are left out of the analysis entirely, such as administrative overhead costs and planning and licensing costs prior to construction. Five factors were varied to determine the bounds of nuclear competitiveness: nuclear plant overnight cost, average capacity factor, natural gas prices, carbon tax rate, and plant economic life. The reasons these parameters were chosen are as follows:

- *Nuclear plant overnight cost* – Because nuclear plants require a large capital investment and have low operating costs, the capital carrying charges tend to dominate the levelized cost. Many studies that reach different conclusions about nuclear competitiveness do so because of different assumptions about the overnight cost. Unfortunately, there is very little actual data on overnight costs for ALWR plants because so few have been built, but some recent overseas experience suggests that $2,000/kW might be a reasonable estimate. Some analyses predict overnight costs in the $1,000 - $1,400/kWe range, which would have a dramatic downward effect on the lifecycle cost. Others are more skeptical that the problems the plagued earlier nuclear development have been solved, and believe that $2,000/kW is extremely optimistic, especially in light of the industry's historical record of underestimating actual construction costs by a factor of three. Of course, in a competitive wholesale market investors must bear the risks of cost overruns so their ultimate investment decisions will be based on credible estimates of construction and operating costs and they will have powerful incentives to control the actual realization of these costs. Moreover, if investors really believe that nuclear plants can be built at a cost less than or equal to a coal plant, competitive markets allow them to place their bets as they see fit. They do not have to convince a regulatory commission that the costs are lower than is widely believed.

- *Average capacity factor* – The capacity factor achieved by an operating plant depends both on its ability to avoid maintenance down-time and on the regional demand for electricity. The focus here is on market demand, which is especially important in the merchant plant case where plants compete to supply electricity. Plants with large fixed costs will suffer when they are not able to produce at full capacity. Capacity factor is treated as an exogenous variable in this analysis, but in reality the decision to produce is driven by the market price for electricity.
- *Natural gas prices* – Of all operating costs for the three technologies, the cost of natural gas is likely to be the most critical because of its volatility and the magnitude of its contribution to the levelized cost of CCGT generation.
- *Carbon tax rate* – The cost analysis is extended to determine the effect on levelized costs in the event that a government entity levies a tax on carbon dioxide

emissions, presumably to reduce a perceived human contribution to global climate change. The imposed tax could also represent the cost of emissions permits under a cap and trade system. In this case, the competitiveness of technologies that burn carbon intensive fuels will diminish.

- *Plant economic life* – The utility case assumes a 30-year economic life, consistent with standard practice. Often, studies that aim to demonstrate the competitiveness of nuclear plants assume a 40 or even 60 year lifetime for nuclear plants, and the recent spate of applications for NRC license renewal lend credence to this decision. What time horizon investors will accept in a merchant plant environment will be discussed when that case is presented.

Figure 4-1 shows the real levelized costs in the base utility case. As expected, nuclear is more expensive than both coal (PC) and gas (CCGT), but not by very much, and coal is slightly cheaper than the combined cycle technology with natural gas prices starting at $4.00/MCF. Also as expected, the cost of nuclear is dominated by the capital investment and the cost of CCGT is primarily fuel. Interest during construction, or AFUDC (Allowance for Funds Used During Construction), accounts for 19% of the total investment cost of a nuclear plant (see Appendix B for the calculation of AFUDC). When the cost of capital is higher, as in the merchant plant case presented in the next chapter, or when construction extends over many years, AFUDC can account for an even larger portion of the total investment cost. Figure 4-2 shows the nominal levelized costs for the three technologies. Notice that all costs are higher when viewed as nominal levelized costs, but the ranking of options remains the same.

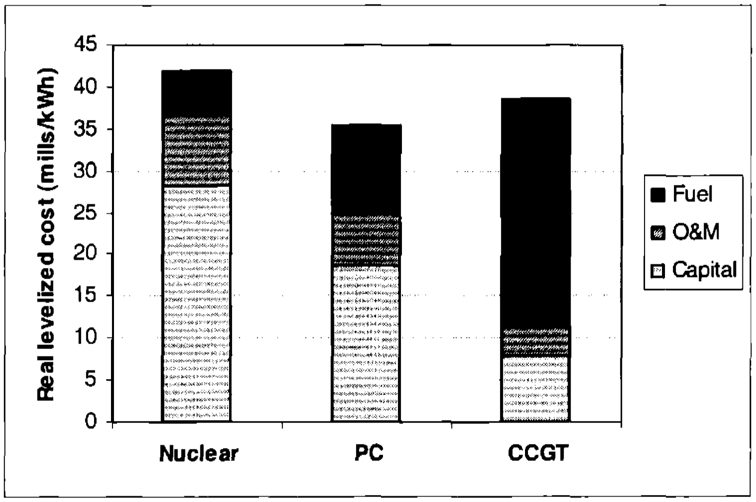

Figure 4-1: Real levelized costs for the utility base case

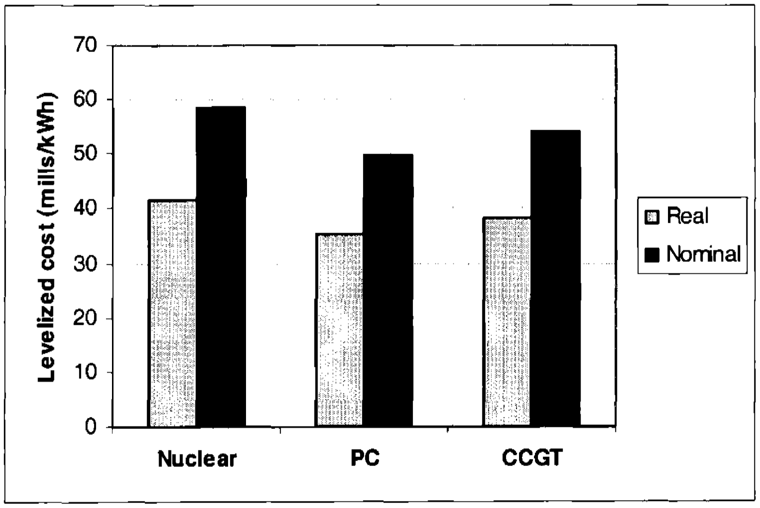

Figure 4-2: Real and nominal levelized costs for the utility base case

Figure 4-3 through Figure 4-6 present the sensitivity cases. Figure 4-3 indicates that nuclear plants become cheaper than CCGT plants when the overnight cost is reduced to about \$1,740/kW, and approach the levelized cost of coal below \$1,500/kW. Figure 4-4 shows the dependence of levelized cost on the average lifetime capacity factor. A nuclear plant with an overnight cost of \$1,200/kW is the low-cost option when the capacity factor exceeds 62%. At lower capacity factors, CCGT technology dominates because it has smaller capital carrying charges. The base nuclear plant only approaches the cost of the CCGT plant at unsustainably high utilization. Figure 4-5 displays the natural gas price and escalation rate that is required to make coal and nuclear plants competitive with CCGT plants. The $1,200/kW nuclear plant is competitive at $3.22/mmBTU with no real price escalation, while the base plant requires gas prices to be $4.78/mmBTU for nuclear to be cheaper than CCGT generation. Finally, Figure 4-6 shows the effect of a carbon tax on each technology option. With a tax of $28/tonne-C, the base nuclear plant becomes competitive with coal, while a tax above $36/tonne-C is required to raise the levelized cost of a CCGT plant above that of a nuclear plant, reflecting the lower carbon content of natural gas and the higher thermodynamic efficiency of the combined cycle plant. A sample of these results is given in Table 4-2 to facilitate comparison to the merchant plant results.

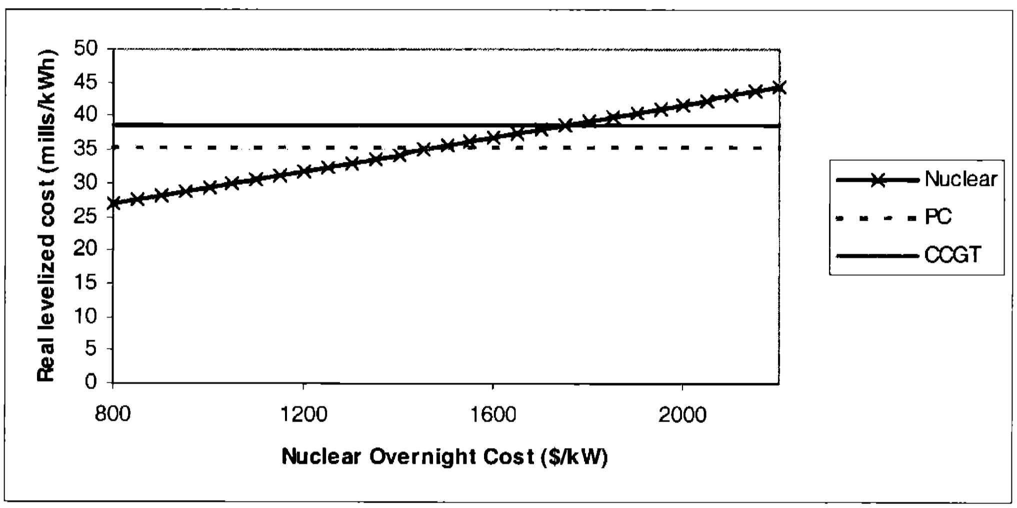

Figure 4-3: Real levelized cost sensitivity - Nuclear overnight cost

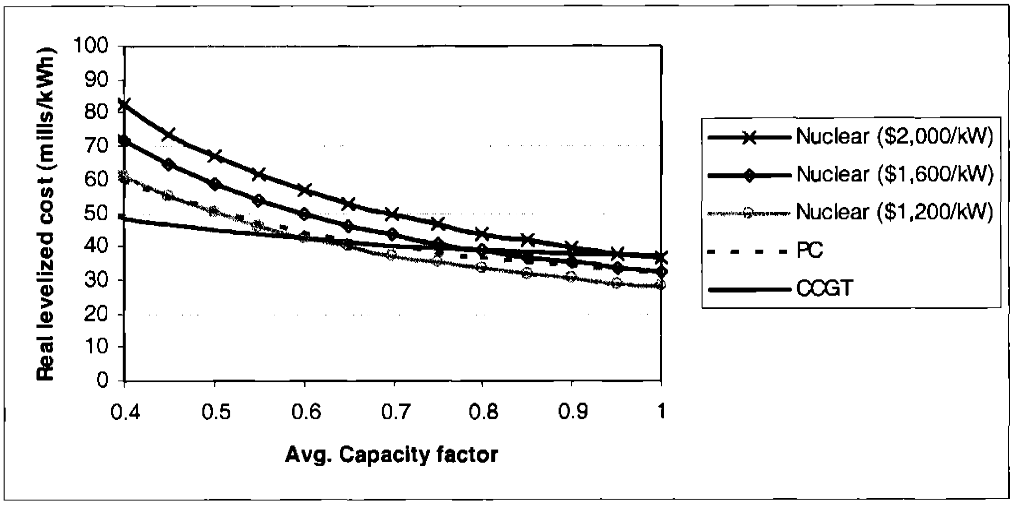

Figure 4-4: Real levelized cost sensitivity - Average capacity factor

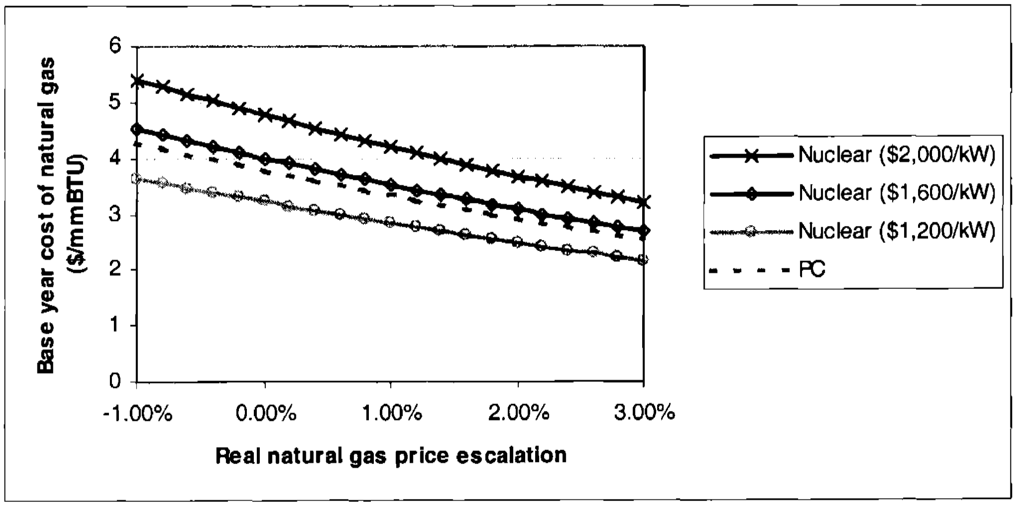

Figure 4-5: Real levelized cost sensitivity - Natural gas prices

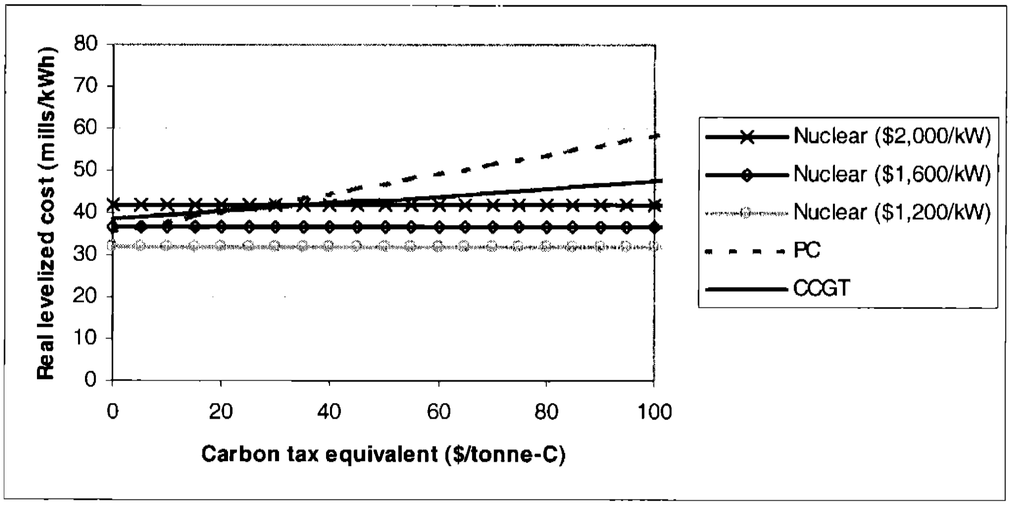

Figure 4-6: Real levelized cost sensitivity - Carbon tax

Table 4-2: Summary of competitive conditions for nuclear plants

4.4.1.. Nuclear plant cost measure	Value
Overnight cost competitive with CCGT	$1,740 / kW
Overnight cost competitive with PC	$1,490 / kW
Minimum capacity factor making $1,200/kW plant the low-cost option	62 %
Break-even gas price for $1,200/kW plant	$3.22 / mmBTU
Break-even gas price for $2,000/kW plant	$4.78 / mmBTU
Break-even carbon tax on PC ($2,000/kW plant)	$28 / tonne-C
Break-even carbon tax on CCGT ($2,000/kW plant)	$36 / tonne-C

To summarize, a regulated utility faced with the choice of generating technologies that have cost and performance characteristics consistent with the assumptions above would not choose to build a nuclear plant, but the levelized cost of a nuclear plant is not out of line with the two fossil plant options. By adjusting key cost assumptions within a practical range, the revenue requirement method indicates that nuclear could become the low-cost technology. This analysis is typical of many studies that support an expansion of nuclear power. The next chapter addresses investment decisions in a competitive generation market, first by using the same revenue requirement methodology, and second by a more detailed look at the project cash flows, to determine whether the results presented above hold when the plant is deployed as a merchant plant and what impact the choice of valuation methodology has on the investment decision.

5 Investment Decisions for Merchant Power Plant Developers

Competitive generation markets introduce new risks to the power producer, as discussed in Chapter 2. A merchant plant owner selling electricity in the spot markets and through contracts with distribution companies or power marketers does not benefit from the market assurance provided by a vertically-integrated monopoly and has no guarantee that operating and financing costs can be passed through to consumers. This chapter re-examines the investment decision from Chapter 4 in the context of a competitive wholesale generation market. First, the revenue requirement method that was used in the utility case is applied to merchant plants by adjusting the financial assumptions to reflect the new market structure. Then a more detailed calculation of investment cash flows is used to provide a second set of results and to assess the validity of the traditional revenue requirement method when applied to investments in merchant plants.

5.1 Merchant plant investment valuation – Revenue requirement method

An intuitive approach to the merchant plant valuation problem is to start with the real levelized cost analysis of the regulated utility and identify the model parameters that differ in a competitive market environment. After all, the levelized cost is simply a representation of the NPV of the project and, as discussed in Chapter 4, the NPV is a standard measure to determine whether an investment is worth pursuing. Whereas in the utility case, the regulator will favor the least-cost alternative in the interest of providing consumers with the lowest possible electricity rates, a merchant project developer will favor the least-cost alternative in the interest of maximizing his profits. It is unlikely that operating costs will be altered appreciably in moving to a competitive wholesale market, assuming that the regulated utility has enough incentive to manage costs.[12] The major change will be in the costs of financing the initial investment, which are reflected in the calculation of the discount rate. Additionally, the investment horizon may be adjusted to

[12] Regulatory commissions employ a variety of tactics to promote efficient operation by utilities. For a brief summary of approaches that have been adopted or considered, see Viscuzi (2003).

more accurately reflect the investment decision. Real option values will be important as well, but that discussion is delayed until Chapter 6.

Financing costs will almost certainly be higher for a merchant plant because of the additional financial risks. Before the plant is operational, investors face the risk of construction delays, cost overruns, and changing market conditions. After operation begins, there is no assurance that the plant will be able to produce electricity at a cost sufficiently below market price and at a rate of production that will provide the returns expected by investors. Standard notions of investment behavior dictate that investors will demand a premium for this additional risk, raising the cost of capital for the project. Even if the project developer manages to reduce direct financing charges by, for instance, drawing on retained earnings or financing primarily through debt and raising the financial leverage of the existing company, the true economic cost of the risky project is not necessarily reduced but merely obscured, as some of the risk and cost of the project is shifted from new investors to current stockholders and creditors.

Just how much higher financing costs will be for a merchant plant depends on the perception of risk, and will likely not be uniform across all technologies. Projects with long and uncertain lead times, such as nuclear plants, will likely demand a substantial premium. Projects with high fixed costs, also characteristic of nuclear plants, will be less responsive to market conditions and will require higher returns (Bodie et al, 1999). Predicting investor demands is not the purpose of this analysis, but standard investment behavior theory suggests that capital for merchant plants will be more costly than it is for a regulated utility plant, and that capital-intensive plants, and nuclear plants especially, will face additional financial hurdles.

The economic lifetime for a power plant was considered to be 30 years in the regulated utility case, based on standard regulatory practice. In a competitive market, the economic lifetime used for analysis should be freed from the constraint of standard regulatory practice to better represent the economic performance of the plant. One argument for lowering the life of the plant is that investors are unlikely to consider cash flows beyond 20 years. Of course, an increased discount rate will tend to make distant cash flows less relevant anyway. Another possibility is to raise the economic lifetime used in the cash flow analysis to match the predicted productive life of the plant. Nuclear plants would get credit for at least 40 years of production, while combined cycle plants might only get credit for 25 years.

Figure 5-1 illustrates the effect of changing the discount rate on the real levelized cost of the technologies under consideration, using the standard cost and performance assumptions. As expected, the increase in discount rate negatively impacts the competitiveness of capital-intensive technologies because higher future cash flows are necessary to recover the large initial capital investment and counter the effect of increased discounting. The economic lifetime of the plant is varied in Figure 5-2, showing that nuclear and coal plants benefit slightly from an extension of their operating life beyond 30 years, but after about 40 years, the costs are discounted so heavily that adding additional years has no effect.

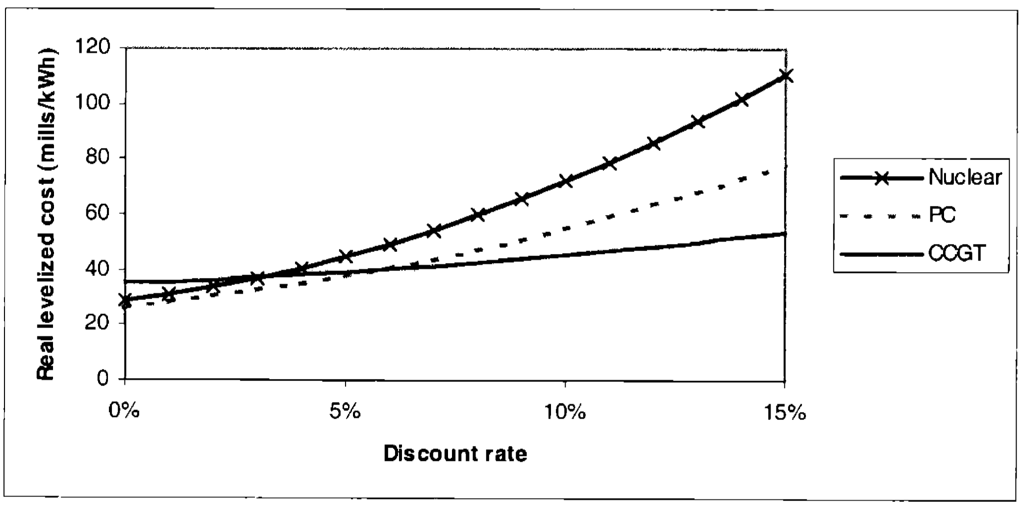

Figure 5-1: Real levelized generation costs at different discount rates

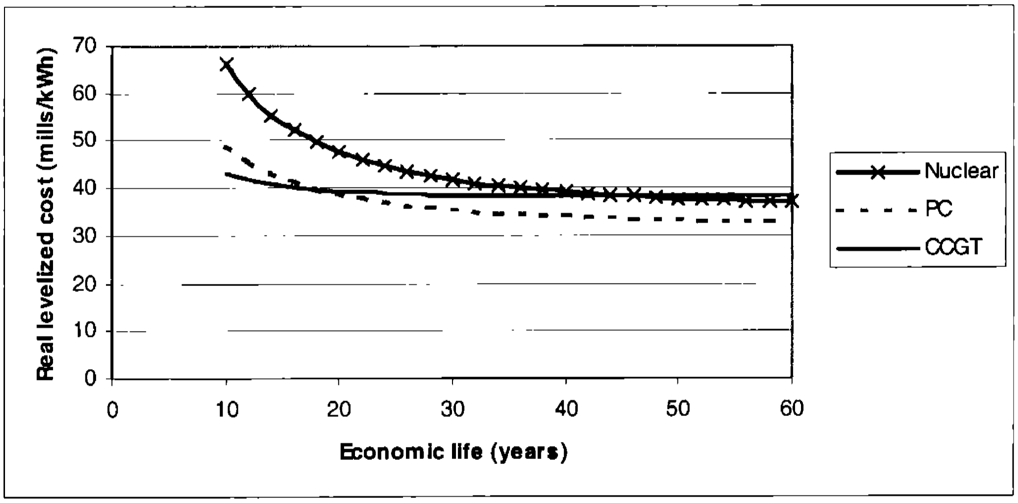

Figure 5-2: Real levelized costs for different assumptions about economic life

Table 5-1 lists the financial parameters that were assumed in the merchant power plant analysis. The financing costs contain modest risk premiums to account for the additional risks discussed above.

Table 5-1: Financial parameters representative of a merchant plant developer

5.1.1. Parameter	Nuclear	PC	CCGT
Nominal interest rate	8%	8%	8%
Nominal after-tax return on equity	15%	13%	12%
General rate of price inflation	3%	3%	3%
Debt ratio (D/V)	50%	60%	60%
Corporate income tax rate	38%	38%	38%
Economic life of plant	40 years	40 years	25 years

RR Model results

The real levelized costs for the base case using the RR model are shown in Figure 5-3. As expected, the increase in the cost of capital has made the nuclear technology much more expensive. Coal is still the most economical option, but its real levelized cost has increased more than that for a CCGT plant. AFUDC accounts for 25% of the total capital cost of a nuclear plant, up from 19% in the utility case.

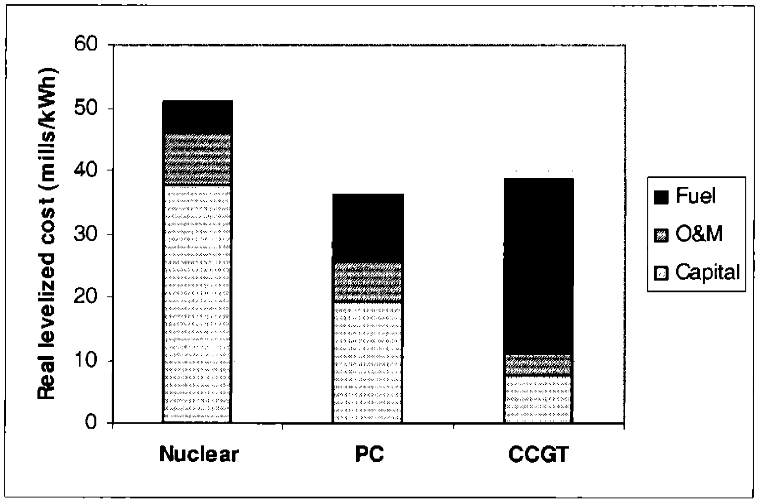

Figure 5-3: Real levelized costs for the merchant base case – RR Model

The same set of sensitivity cases used in the regulated utility case was used in the merchant plant case. With the new financial parameters, the nuclear overnight cost must drop to $1,525/kW to compete with CCGT, and almost $1,400/kW to challenge the coal plant, compared to $1,740/kW and $1,490/kW respectively in the utility case. The cost of capital for the nuclear plant was reduced as the expected overnight cost decreased, reflecting the lower investment risk, to where a nuclear plant with an overnight cost of $1,200/kW faced similar financing conditions as a coal plant. The $1,200/kW nuclear plant is still the low-cost technology for capacity factors over 65% but for overnight costs over $1,600/kW, nuclear plants are dominated by coal and CCGT regardless of the capacity factor. The break-even price for natural gas has risen to $6.25/mmBTU (real levelized) for the $2,000/kW nuclear plant, up from $4.78/mmBTU in the regulated utility case. Finally, the carbon tax rate that would be required to equalize the costs of nuclear and CCGT plants has increased by $100/tonne-C to $136/tonne-C. A smaller carbon tax is enough to make coal uncompetitive with nuclear technology because coal plants have are similarly capital-intensive and a carbon tax would be heavily burdensome when burning carbon-intensive coal. The sensitivity cases are summarized in Table 5-2, along with the corresponding values for the regulated utility case.

Table 5-2: Summary of competitive conditions for nuclear plants (2)

5.1.1.. Nuclear plant cost measure	Utility case	Merchant plant case
Overnight cost competitive with CCGT	\$1,740 / kW	**\$1,525 / kW**
Overnight cost competitive with PC	\$1,490 / kW	**\$1,415 / kW**
Minimum capacity factor making \$1,200/kW plant the low-cost option	62 %	**63%**
Break-even gas price for \$1,200/kW plant	\$3.22 / mmBTU	**\$3.25 / mmBTU**
Break-even gas price for \$2,000/kW plant	\$4.78 / mmBTU	**\$6.25 / mmBTU**
Break-even carbon tax on PC (\$2,000/kW plant)	\$28 / tonne-C	**\$66 / tonne-C**
Break-even carbon tax on CCGT (\$2,000/kW plant)	\$36 / tonne-C	**\$136 / tonne-C**

The results indicate that raising the discount rate to reflect the higher cost of capital for a merchant plant reduces the set of circumstances under which nuclear plants are competitive. The next section takes a closer look at the project cash flows to determine if the revenue requirement approach provides an acceptable measure of economic performance.

5.2 Merchant plant investment valuation – Flows to equity method

A more direct method of valuing an investment calls for an explicit calculation of projected net cash flows available for distribution to equity investors in each year of operation, sometimes referred to as the flows-to-equity method. This approach is reflected in the model described in Appendix C, and will henceforth be referred to as the merchant plant (MP) model. Taxes and payments on debt are subtracted from annual operating income before discounting the stream of cash flows at the cost of equity[13], as opposed to the revenue requirement method where taxes and interest on debt are rolled into the calculation of the WACC. This approach takes the shareholder's view of an investment and, because of its explicit treatment of project financing, it is particularly applicable to power plant investments where financing costs are a significant portion of the total lifecycle cost. It also allows closer investigation of near-term financial performance of the project.

The primary advantage of the MP model is that it relaxes the tight constraints placed on debt financing in the RR model. Instead of requiring the debt to be repaid over the full life of the project in a way that maintains the proportions of debt and equity, as assumed in the WACC formulation, the MP model allows the full range of debt terms and repayment provisions. This flexibility comes at the expense of sacrificing the convenient closed form levelized cost calculation derived in Appendix B, though the notion of levelized cost is still applicable as an annuity equivalent to the project's total discounted cost. Reducing the debt term will delay cash flows to equity holders as more free cash flow is committed to creditors, reducing the value of the cash flows. A secondary opposing effect comes from the increased interest tax shield in early years. Shorter debt terms may also threaten the firm's ability to meet debt coverage obligations. In the MP model, if revenues are insufficient to provide an acceptable level of debt coverage, then the electricity price, still referred to as the real levelized cost, must be increased. In cases where the debt constraint is binding, the constant electricity price required to support the investment will be higher than if the only constraint were the return on equity. The model solution criteria are discussed in Appendix C.

---

[13] Selection of the appropriate cost of equity is the topic of much academic discussion. When debt principal is repaid, the leverage of the firm changes, and this should reduce the cost of equity as fixed claims on income are reduced. The approach used here disregards this effect and uses a constant discount rate for flows to equity holders. For more discussion of discount rate selection, see Brealey and Myers (2003).

The income tax liability is calculated for each year of operation in the MP model. In the early years, when depreciation and interest payments are substantial, the project's pre-tax income net of depreciation and interest expenses may be negative, requiring no income tax payments. Instead of using straight-line depreciation, as in the revenue requirement approach, accelerated tax depreciation schedules can be used to reduce the tax liability in the early years of the project. Consistent with federal tax law, interest during construction, but not an imputed return on equity, is included in the depreciable asset base in the MP model, a detail that is lost when financing decisions are subsumed by the discount rate.

The MP model also allows detection of situations where it is uneconomic to run the plant. In the RR model, the levelized cost of fuel is a simple function of the base year fuel cost and the assumed escalation rate of fuel prices. It fails to capture the decision to cease operation when marginal production costs exceed marginal revenues, as may happen if fuel prices escalate rapidly. The effect of the early shutdown decision can be reflected in the MP model.

Model parameters

Most of the cost and performance parameters used in the application of the RR model to merchant power plant investment carry over to the MP model. However, the base case using the MP model assumes that debt is repaid using mortgage-style repayments over 15 years and that the project must maintain a debt coverage ratio of 1.5. The term is varied, along with principal repayment provisions, in a variant sensitivity study. Two distinct periods of debt financing are assumed; one during construction and one after the plant is operational. The interest rate during construction is higher because of the risk of construction delays and cost overruns. Once the plant is operational, the debt is refinanced at a lower rate. The cost of equity is unchanged. Accelerated depreciation, using the Modified Accelerated Cost Recovery System (MACRS) is used for the calculation of tax liability, with a recovery period of 15 years for the nuclear plant and 20 years for the fossil plants, consistent with the current federal tax code.

In the case of escalating costs (specifically, escalating natural gas prices), the plant will cease production when annual operating expenses exceed annual revenues. This is a simplified approach that disregards the costs of abandoning a plant or maintaining it for future use if factor costs drop, but it is sufficient for the purposes of this analysis. Fluctuations of fuel and electricity prices on a smaller time scale that may prompt temporary inactivity are captured in the assumed capacity factor, which is an exogenous parameter, as in the RR model. It is also assumed that if the plant is shut down early, it will not be replaced with new capacity. The nature of the sensitivity study does not warrant more rigorous treatment of the shut-down decision.

Model results

The real levelized costs for the base case using the MP model are shown in Figure 5-4 alongside equivalent real costs produced by the RR model. The results imply that capital-intensive projects are even less likely to be built when cash flows to equity holders are calculated explicitly. This is not surprising, given that creditors lay claim to more of the free cash flow in the early years. With the increased cost of equity forced by market competition, the postponement of returns to equity has a notable effect on the project valuation. Unlike the previous case, CCGT is now the low-cost option, and the cost of the nuclear plant is well above the cost of the fossil plants.

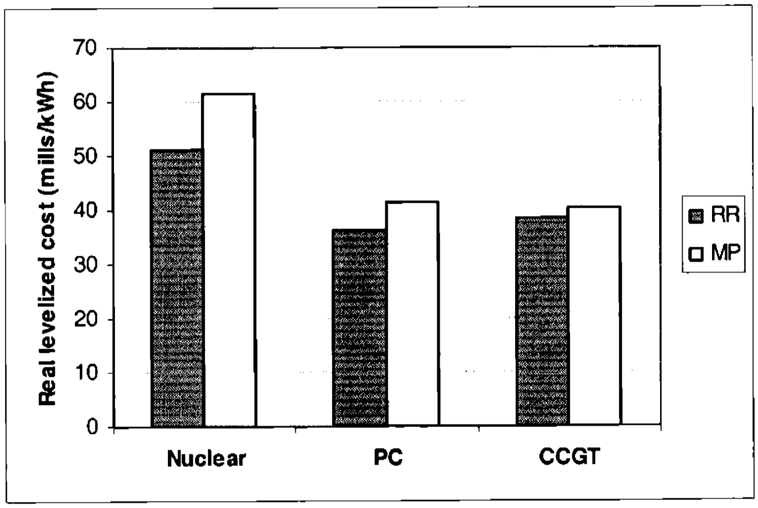

Figure 5-4: Real levelized costs for the merchant base case – MP model

Figure 5-5 through Figure 5-8 display the results of the sensitivity analysis. The range of assumptions under which nuclear plants are competitive continues to contract to the extent that dramatic changes to current conditions would be necessary for nuclear investment to be a viable consideration. Holding everything else equal, to be competitive with CCGT, either the nuclear plant overnight cost would have to be reduced to $1,315/kW, the real levelized natural gas price over the operating life would have to be $7.53/mmBTU, or a carbon tax over $200/tonne-C would have to be in place. Table 5-3 compares all three valuation approaches using selected samples of the results.

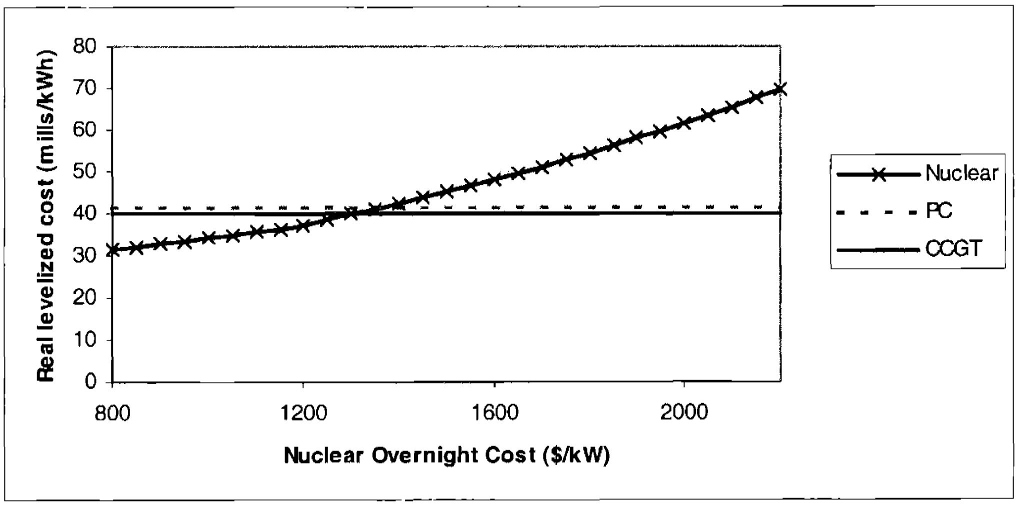

Figure 5-5: Real levelized cost sensitivity - Nuclear overnight cost

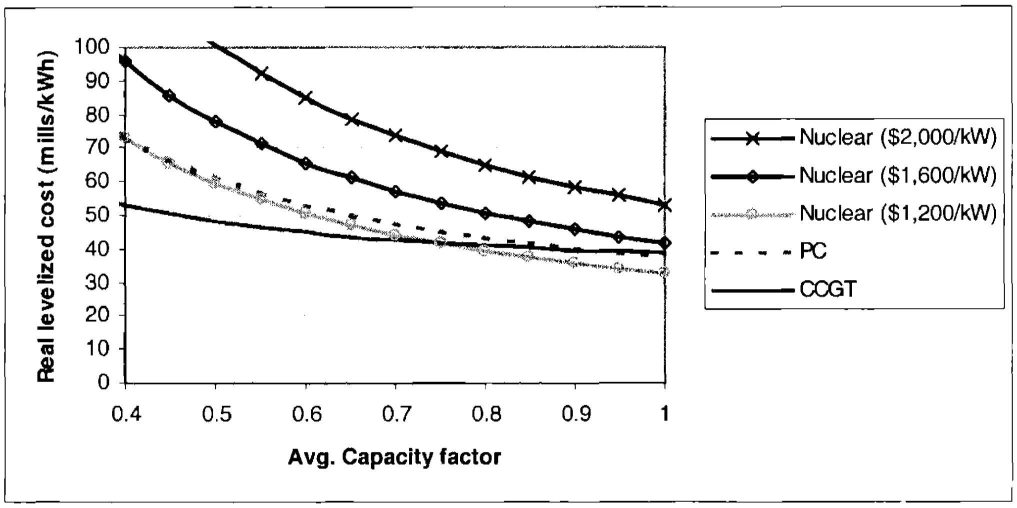

Figure 5-6: Real levelized cost sensitivity - Average capacity factor

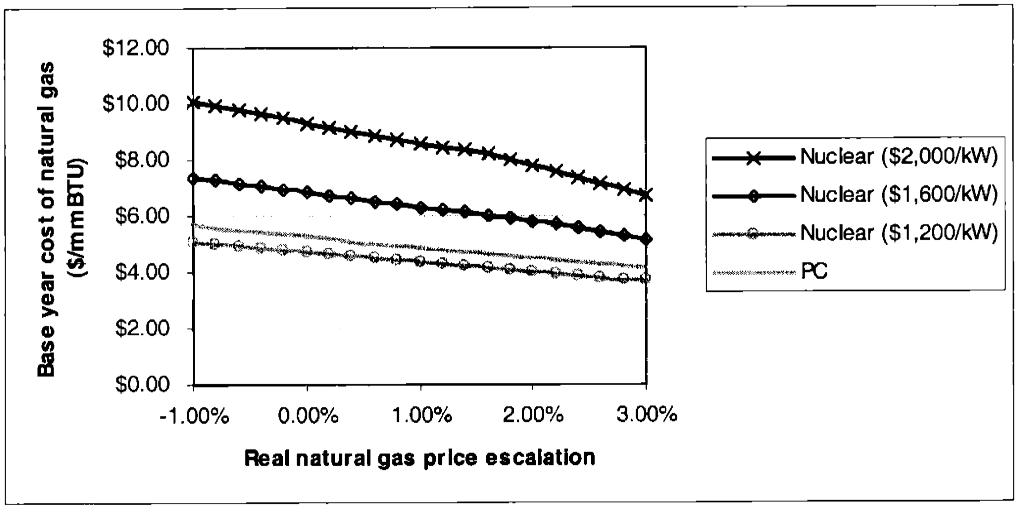

Figure 5-7: Real levelized cost sensitivity - Natural gas prices

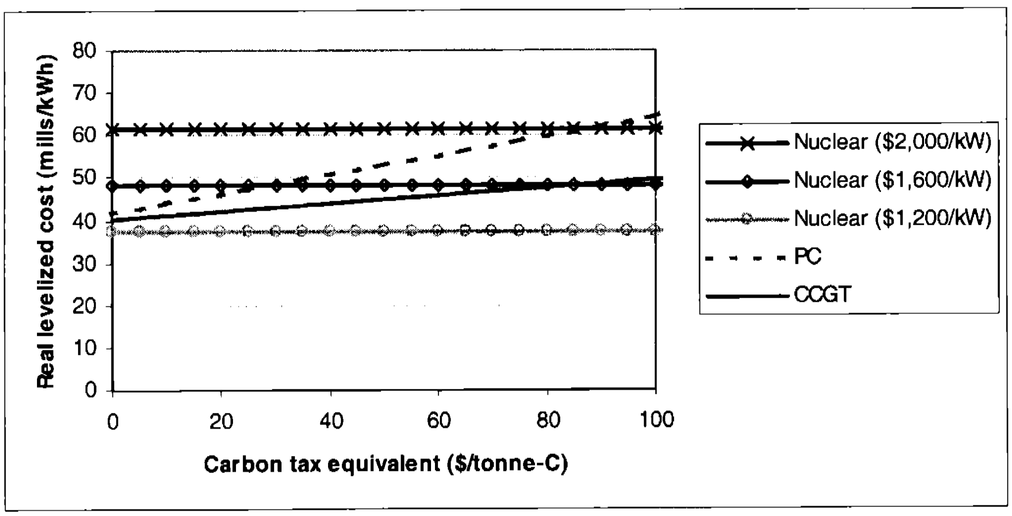

Figure 5-8: Real levelized cost sensitivity - Carbon tax

Table 5-3: Summary of competitive conditions for nuclear plants (3)

5.2.1.. Nuclear plant cost measure	Utility case - WACC	Merchant case -WACC	Merchant case –FTE
Overnight cost competitive with CCGT	$1,740 / kW	$1,525 / kW	**$1,315 / kW**
Overnight cost competitive with PC	$1,490 / kW	$1,415 / kW	**$1,370 / kW**
Minimum capacity factor making $1,200/kW plant the low-cost option	62 %	63%	**74%**
Break-even gas price for $1,200/kW plant	$3.22 / mmBTU	$3.25 / mmBTU	**$3.74 / mmBTU**
Break-even gas price for $2,000/kW plant	$4.78 / mmBTU	$6.25 / mmBTU	**$7.53 / mmBTU**
Break-even carbon tax on PC ($2,000/kW plant)	$28 / tonne-C	$66 / tonne-C	**$89 / tonne-C**
Break-even carbon tax on CCGT ($2,000/kW plant)	$36 / tonne-C	$136 / tonne-C	**$231 / tonne-C**

A closer look at debt provisions

There are numerous ways to borrow money for a new construction project, including a bank construction loan and a bond issuance. Loans and bonds can differ in their maturities, repayment provisions, and restrictions on future issues. The supposition here is that the fine details of the debt instruments selected are not critical because the cost of the debt will depend on the project's risk at a given point of development. Creditors will expect compensation for, or reduced exposure to, that risk so that the return is commensurate with the risk regardless of the specific details. The project developers or investment banks will select the instruments that are best suited to the financial situation of the firm. Still, it is worth looking at the sensitivity of the levelized cost to changes in the debt provisions to determine how critical the base case assumptions are.

First, the term of the debt was changed from 15 years to 10 and then 20 years without changing the interest rate. The shorter debt term raises the levelized cost of the base nuclear plant 3 mills/kWh while the longer term reduces it by 2 mills/kWh, to 60 mills/kWh. A comparable reduction is achieved by allowing a two-year grace period on principal repayments. The debt coverage requirement is not binding in the nuclear base case because of the relatively high cost of equity and larger percentage of equity financing. It could become important with a lower assumed cost of equity or if the average electricity price in the early years of operation is too low or the plant fails to achieve an initial 85% capacity factor. For example, if the base nuclear plant experienced problems upon start-up and only managed a 60% capacity factor in its first year of operation, the coverage requirement would be violated, indicating the potential benefit of a grace period.

The preceding analysis suggests that the current transition to competitive wholesale generation markets, where plant owners assume most of the project and market risk, is likely to discourage investment in capital-intensive technologies such as nuclear power. When cash flows to equity holders are calculated explicitly assuming realistic debt terms, the effect is magnified, suggesting that studies using the revenue requirement approach or a similar method for investments in merchant plants may produce misleading results.

The next chapter briefly addresses some additional concerns not captured in standard discounted cash flow analysis that are likely to affect the selection of base load generation technology.

6 Considerations Beyond Traditional Cash Flow Valuation

The two approaches to power plant investment valuation presented in Chapter 4 and Chapter 5 are examples of traditional textbook discounted cash flow valuation using expected values for uncertain cash flows. In both cases, the calculated levelized cost provides a single measure of the total cost of the investment. In reality, a firm must consider other issues when making investment decisions that are not captured when the expected value of all project cash flows are discounted to present value and accumulated. This chapter identifies a number of other issues that affect the investment decision, without providing a quantitative or in-depth discussion. In some cases, the effect that these factors have on the investment decision depends strongly on the specific circumstances of the firm and the market environment. A more refined approach to investment decisions under conditions of uncertainty is briefly mentioned along with a qualitative discussion of what impact it might have on investments in generation resources. This real options approach to valuation currently is receiving a great deal of attention in many fields of study, including corporate finance and engineering system design.

Making investment decisions simply by comparing levelized costs ignores the time dependency of project cash flows and the impact on standard financial accounts. Company officers must be cognizant of the effect that an investment will have on the short-term financial position of the company. The merchant model in Chapter 5 captured to some degree the consideration of near-term cash flow problems by requiring that the project exceed a minimum debt coverage ratio. Firms also pay close attention to their near-term earnings and total debt load because these are measures that are closely watched by investors. Investor pessimism tends to increase the cost of raising future capital, which will have a direct negative effect on the firm. Any differences in how plants using alternate generation technologies affect the short-term financial position of the firm can affect the investment decision.

Use of the levelized cost also ignores information that the project developer may have about future market conditions and price trends. Electricity prices certainly will not remain constant over the life of the plant, and plants with different cost characteristics will respond differently to price changes. The capacity factor chosen in the analysis implies that the base load plant will generate a given amount of electricity each year, but in reality, the capacity factor, or the percentage of time that the plant is producing electricity, will depend on market prices. Expectations of escalating or decreasing electricity prices, or knowledge of future capacity additions that will affect clearing prices, will have differing impacts on the revenue profile of the plant depending on the technology chosen, and may be a factor in the investment decision. The ability to respond to unforeseen market price trends is addressed below in the discussion of real options.

Another important consideration is the dependence on expected values in standard discounted cash flow analysis. For some model parameters, determining an expected value that accurately reflects the range of possible values is difficult, if not futile. For example, the lead time for a nuclear plant was assumed to be five years in the analysis. However, as things now stand, there is a great deal of uncertainty in this figure, and the uncertainty is asymmetric; that is, the actual construction time for a nuclear plant is not likely to be much shorter than five years, and could be much longer. The same can be said for the nuclear overnight cost, simply because of a lack of empirical data supporting an estimate. These important uncertainties are difficult to capture in the standard analysis, either by adjusting the expected value or by increasing the discount rate to reflect the higher level of risk. In actuality, until these uncertainties are resolved, outside financing for new nuclear plants may be very difficult to secure.

6.1 Real options analysis

It is important to include mention of real options analysis in a discussion of power plant investment decisions because the value of the "flexibility options" inherent in the base load generation technologies under investigation are likely to differ considerably, which will alter the conditions under which a given technology is optimal. As will be seen, inclusion of real option values will expand the economic gap between CCGT and nuclear power plants. The following discussion of real options analysis is drawn from Dixit and Pindyck (1994).

Decision models that make use of the standard NPV criteria, including the model used in this analysis, tend to assume that an irreversible decision is made to invest capital in a project at a point in time, call it time zero. If the expected net value of the project at the time of the decision is positive, then the correct decision is to invest. Alternately, if two or more projects are being compared and only one will be pursued, then the one with the highest (positive) NPV will be selected. In many cases, this provides the optimal solution. However, it does not consider the possibility of waiting for a period of time, possibly foregoing project revenue, and then deciding whether to invest after additional information has been collected and an updated valuation can be made. If the NPV from investing at time one after some uncertainty has been resolved is greater than the NPV from investing at time zero, then the optimal decision is to wait to (possibly) invest. This adds an additional opportunity cost to investing at time zero that is not captured in the standard NPV models.

Real options analysis also treats investment decisions as irreversible, but it allows for adjustment of the timing of the investment. For waiting to have any value, there must be some uncertainty about future costs or market conditions that is expected to be at least partially resolved during the waiting period. If new information suggests that desirable economic conditions are more likely, then the decision may be to invest. Alternately, if the information gathered shows less promising conditions, the project plan may be scrapped or modified to better fit the more informed economic projection. This option to wait is not necessarily free, as the project may require some expenditure to maintain the option of investing later, but as long as the option value exceeds its cost, the optimal solution is to wait. The greater the uncertainty that can be resolved, the more advantageous it is to wait and thus the higher the option value. The technique for quantitative valuation of real options borrows from the concept of financial options and is not discussed here, but a thorough treatment is given by Dixit and Pindyck.

Option values have a number of important ramifications in power plant investment analysis. Capital invested in a power plant is generally assumed to be "sunk" in the sense that it not easily re-deployed for other uses, making the investment decision irreversible. Competitive wholesale markets exhibit demand and price uncertainty as discussed earlier, and information gleaned from further market observation can reduce this uncertainty. In this case, the option to wait until market conditions are more certain can be very valuable. This is best illustrated through an example.

First, assume that the only uncertainty is the magnitude of demand growth. (This is a contrived example in the sense that prices are dependent on demand in a competitive market, but it is nonetheless illustrative. The example is adapted from Dixit and Pindyck.) The expected shortage of base load capacity five years from now is 1,000 MW, but there is uncertainty in this projection. The standard NPV analysis would compare three investment options (leaving coal plants out of the discussion for simplicity): begin building 1,000 MW of nuclear capacity now, commit to building 1,000 MW of CCGT capacity now, or do not invest anything. This ignores the flexibility provided by short lead time and smaller unit sizes of CCGT technology. An additional option could be to build 500 MW of CCGT capacity now and observe trends in electricity demand growth. In two years, if demand growth is strong, then build an additional 500 MW of CCGT capacity, which will be ready for production by the time the nuclear plant would have been. If demand growth is weaker than expected, the additional capacity could be shelved or postponed. It may also be optimal to delay all 1,000 MW of CCGT capacity for two years. Based on information gleaned during that period, the decision could then be made to build 500 or 1,000 MW of capacity. For the nuclear plant, to be available in five years, construction must begin immediately. There is the option to abandon the project after two years if demand projections weaken, but at that point the sunk cost of construction is already considerable. Clearly, when future demand is uncertain, technologies with short lead times and smaller unit sizes have an additional advantage, or an option value.[14]

Uncertainty in future electricity prices or natural gas prices also lead to positive option values for CCGT projects. The important point is that the developer can wait, observe the market, and then commit capital based on additional information. If natural gas prices escalate more rapidly than expected, then the project can be deferred or a different technology selected. Merchant plants do not have a requirement to serve, like regulated utilities do, so it may be optimal after observing a trend to higher natural gas prices to begin construction of a nuclear plant and forego any revenues in the first few years of capacity shortage.[15] CCGT plants also have the option to switch to other petroleum fuels if, after production begins, natural gas prices rise enough to make the transition worthwhile, and as with all projects, CCGT operators have the option to abandon the project early if it is economical to do so. The important difference is that with a nuclear plant, most of the cost of the plant is sunk by the time a decision is made to cease operation. The option has a higher value for CCGT plants because more of the total cost can be avoided when the decision is made.

The following example illustrates why the option to cease operation early if conditions warrant is more valuable for CCGT plants than for nuclear plants. Assume that two alternate investments are being considered: 1,000 MW of nuclear capacity with an expected overnight cost of $1,600/kW, and 1,000 MW of CCGT capacity where natural gas prices are expected to be $4.69/mmBTU (real) levelized over the life of the plant and a carbon tax of $50/tonne-C is in place. Based on the previous analysis, these two projects are equally attractive; that is, their real levelized costs are equivalent. Figure 6-1 shows the present value of the annual costs for the project, including construction

[14] See Gardner and Rogers (1999) for a demonstration of the effect of technology lead time on the mix of generating capacity.
[15] This is not meant to imply that option values are nonexistent for regulated utilities. For an application of real options analysis to regulated utilities, see Teisberg (1994).

expenditures, operating costs, and income taxes. Now suppose that a change in costs or market conditions occurs at year ten that makes it uneconomical to run the plant. More of the total cost can be avoided in the CCGT option, so that the total NPV of the abridged project is higher for the CCGT option than for the nuclear option. Figure 6-2 shows that if the plant ceases operation after ten years, the net loss for the nuclear plant is more than triple that for the CCGT plant, assuming that the wholesale price of electricity remains constant over the ten year period at the real levelized cost of the plants. Of course, with its lower operating costs, it may be economic to run a nuclear plant under conditions that would force a CCGT plant out of operation, but there is an advantage, and thus additional value, to being able to avoid costs when future conditions change.

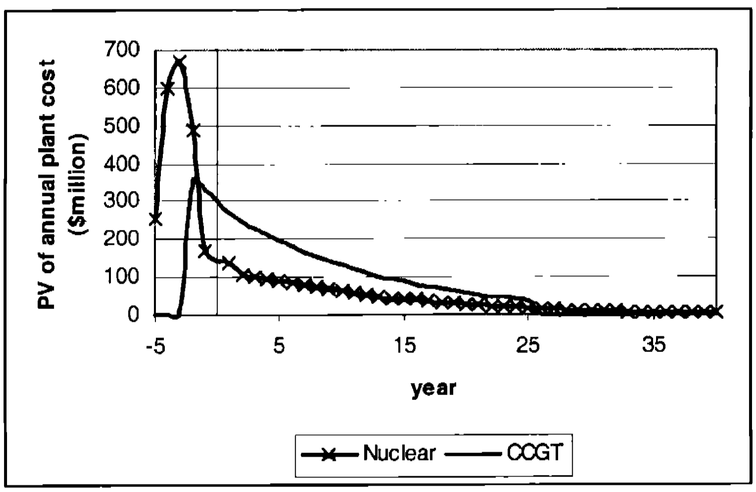

Figure 6-1: Present value of annual costs for nuclear and CCGT plants

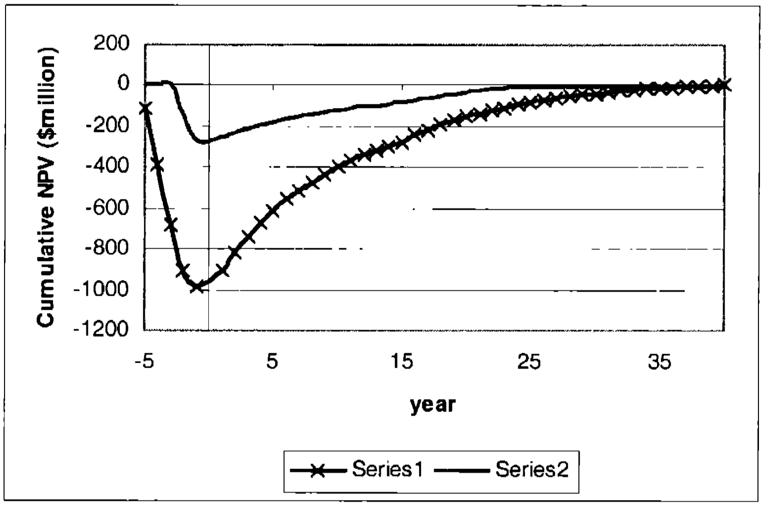

Figure 6-2: Cumulative NPV for nuclear and CCGT plants

These option values are likely to have an important impact on the choice of generation technology in a competitive wholesale market. Quantifying their value requires additional assumptions about the stochastic behavior of electricity and natural gas market prices. Options analysis also provides some insight into what actions and design features could improve the competitive position of a certain technology. For instance, a few nuclear plant operators have recently applied to the NRC for early site permits (ESP). This is a low cost option that will reduce the lead time for a nuclear plant when favorable market conditions are observed. New nuclear designs, such as the Pebble Bed Modular Reactor (PBMR) hold the promise of both shorter construction time and smaller unit size, and are being promoted by some as the nuclear solution for competitive markets (Talbot (2002), Kadak (2000)). Options analysis helps explain the current dominance of CCGT in supplying new base load capacity and suggests that the trend may continue even under conditions where standard NPV analysis favors coal or nuclear technology.

7 Conclusion

In this thesis, the transition to competitive wholesale markets was shown to have a negative effect on the prospects for investment in capital-intensive technologies to supply base load power, particularly for investments in new nuclear power plants. Additionally, the revenue requirement method that is commonly used to compare generation alternatives was shown to underestimate substantially the magnitude of this effect. The investment decision was evaluated through the use of a case study that identified under what conditions – the range of nuclear plant overnight costs, natural gas prices, and an imposed carbon tax - investment in new nuclear plants would emerge. The analysis shows that for a new merchant nuclear plant to be competitive with a CCGT plant, either the overnight cost would have to be reduced to close to $1,300/kW, gas prices would have to rise above $7/mmBTU, or a carbon tax over $200/tonne-C would be necessary.

When the costs of financing a new plant are treated explicitly, the revenue that is required over the life of the plant to support the investment increases as cash flows to equity investors are delayed to meet debt repayment obligations. The higher required returns, resulting from investors assuming more of the project development and market risk, and the delayed payments to equity investors have a compounding effect, making capital-intensive projects like nuclear power plants less attractive to investors, and therefore less likely to emerge in a competitive wholesale market. When real options considerations are included in the analysis, future investment in nuclear power becomes even less likely unless new designs can reduce the lead time and the construction cost for a plant.

This result implies that economic studies comparing alternative generation technologies may fail to accurately predict investor behavior if the true nature of merchant plant financing is not considered. This is important because simple economic studies like this are frequently undertaken in an effort to influence energy policy decisions. Failure to consider the true costs and risks that merchant plant developers face will lead to incorrect assumptions about investment behavior and to potentially ineffective and expensive government policies.

8 Appendix A: List of Symbols

α	Carbon coefficient of fuel (kg-C/mmBTU)
τ	Corporate income tax rate
τ_{Carbon}	Equivalent carbon tax ($/tonne-C)
Φ	Average capacity factor
c_{Cap}	Levelized capital cost (mills/kWh)
c_{Carbon}	Levelized cost of carbon tax (mills/kWh)
c_{Fuel}	Levelized fuel cost (mills/kWh)
c_I	Levelized investment cost (mills/kWh)
$c_{O\&M}$	Levelized O&M cost (mills/kWh)
C_{Capx}	Annual capital expenditures ($/kW-yr)
C_{Decom}	Nuclear decommissioning cost ($million)
C_{Fuel}	Fuel acquisition cost ($/mmBTU)
C_{NWF}	Nuclear waste fee (mills/kWh)
$C_{O\&M,f}$	Annual fixed O&M costs ($/kW-yr)
$C_{O\&M,v}$	Variable O&M costs (mills/kWh)
D	Total debt capital
e_i	General rate of price inflation
e'_{Fuel}	Real escalation rate of fuel costs
$e'_{O\&M}$	Real escalation rate of O&M costs
E	Total equity capital
G	Plant net rated capacity (MW)
N	Economic life of the plant (years)
OC	Plant overnight cost ($/kW)
r	Nominal after-tax weighted-average cost of capital (WACC)
r'	Real after-tax weighted-average cost of capital (WACC)
r_D	Nominal cost of debt (nominal interest rate)
r'_D	Real cost of debt (real interest rate)
r_E	Nominal cost of equity

r'_E	Real cost of equity
T_c	Construction period (years)
TC	Plant total investment cost ($/kW)
V	Total value of the firm/project (V = D + E)

9 Appendix B: Revenue Requirement (RR) Valuation Model

This appendix contains a description of the revenue requirement (RR) model used to evaluate investments in base load generation resources for a regulated utility. The model is applicable to both current dollar and constant dollar analyses but the expressions given here are in constant dollar form. In most cases, the current dollar equivalent is obtained simply by replacing the real WACC with the nominal WACC and real escalation rates with nominal escalation rates. The result will then be a nominal levelized cost instead of a real levelized cost.

The RR model calculates the real levelized cost of electric power generation. The levelized cost is disaggregated into levelized capital costs, operations and maintenance (O&M) costs, and fuel costs, and each element can be understood to approximate the amount of revenue (per kWh) that is required to support the associated cost. Closed form expressions for these three elements are derived below. The following assumptions underlie the derivations:

- Cash flows are discrete functions of time. All expenses and capital expenditures during a given year are treated as if they occurred at the beginning or end of the year.
- All capital expenditures occur at the beginning of the year. All operating expenses, taxes, depreciation, and financing charges occur at the end of the year. This is consistent with the methodology in the TAG™.
- The commencement of commercial operation is denoted as year 0. The first expenses occur in year 1. The last year of construction expenditures is year −1.
- Costs are specified on a per-unit basis. Fixed costs are specified in dollars per kilowatt ($/kW) of capacity. Variable costs are specified in mills[16] per kilowatt-

[16] A mill is one tenth of a cent, or one thousandth of a dollar.

hour (mills/kWh) of electricity generation. Real levelized costs are also specified in mills/kWh.

- The overnight cost is specified in dollars of the year that the plant enters operation, as opposed to the year that construction begins. This can be significant in the case of a long construction period because the early years of construction occur when prices are lower, assuming positive inflation. The overnight cost includes all equipment, labor, engineering, owner's site costs, and project contingency funds.
- Costs subject to real price escalation, specifically fuel and O&M costs, are specified in dollars of the year operation begins. Price escalation begins at this time.

Present value formulas

The real levelized cost expressions make use of a number of standard mathematical formulas that equate cash flows over time. The formulas are listed in Table 9-1. The notation is borrowed from Park and Sharp-Bette (1990).

Table 9-1: Standard time value of money equivalence formulas

Factor	Notation	Formula	
Present Worth	*(P/F, i, N)*	$P = F(1+i)^{-N}$	P = value at t = 0
Sinking Fund	*(A/F, i, N)*	$A = F\left[\frac{i}{(1+i)^N - 1}\right]$	F = value at t = N A = value of constant stream (annuity) from t = 1..N
Capital Recovery	*(A/P, i, N)*	$A = P\left[\frac{i(1+i)^N}{(1+i)^N - 1}\right]$	F_1 = value at t = 1 of an escalating series ($F_2 = F_1 (1 + g)$)
Present Worth of a Gradient Series	*(P/A, g, i, N)*	$P = \begin{cases} F_1\left[\frac{1-(1+g)^N(1+i)^{-N}}{i-g}\right] \\ \frac{NF_1}{1+i} \quad if(i=g) \end{cases}$	i = discount rate g = growth rate

Source: Park and Sharp-Bette (1990).

Real levelized capital cost

The calculation of the real levelized capital cost is more involved than that for the other elements because construction expenditures must be accounted for properly and because of the depreciation tax shield. Expenditures during construction are assumed to start at a low level at the beginning of the construction period, reach a peak at mid-construction, and ramp down to nothing by the start of commercial operation. This construction profile is approximated by a sinusoidal function, where the percentage of construction completed in year t is

$$\phi_t = \int_{t+T_c}^{t+T_c+1} \frac{\pi}{2T_c} \sin\left(\frac{\pi x}{T_c}\right) dx = \frac{1}{2}\left[\cos\left(\frac{\pi(t+T_c)}{T_c}\right) - \cos\left(\frac{\pi(t+T_c+1)}{T_c}\right)\right]$$

The expenditure in year t, X_t, in constant dollars, is then

$$X_t = \phi_t \cdot OC$$

where OC is the overnight cost of the plant, or the cost in year 0 dollars that would be required to build the plant overnight, ignoring interest and inflation. The estimated cost to build a power plant is frequently quoted as an overnight cost.

The total plant cost, TC, includes time-related charges and is the present value of the stream of construction expenditures. It is this cost that is used as the basis for depreciation.[17]

[17] Tax rules do not allow for the inclusion in the depreciable asset base of imputed interest on equity financing during construction. Using the total plant cost, TC, as the asset base is an approximation that maintains the separation of financing and project investment. This is also consistent with regulatory cost accounting procedures.

$$TC = \sum_{t=-T_c}^{-1} X_t (1+r')^{-t}$$

Though not required for the calculation of real levelized capital cost, often it is informative to calculate the allowance for funds using during construction, or AFUDC. This is the difference between the total plant cost (in year 0 dollars) and the sum of the capital expenditures in mixed-year dollars. For long construction projects, these time-related charges can be a large portion of the total investment.

$$AFUDC = TC - \sum_{t=-T_c}^{-1} X_t (1+e_i)^t$$

Once the total plant cost is determined, it can be levelized over the life of the plant. Before levelizing, it is convenient to calculate the present value of the depreciation tax shield, which can be subtracted from the total cost because it decreases the revenues required to support the capital investment. Straight-line depreciation is used in the RR model for simplicity and to be consistent with TAG™ assessment guidelines. The value of the depreciation tax shield in each year in current dollars is equal to the depreciation allowance multiplied by the corporate income tax rate. Discounting the constant cash flow in current dollars using the real discount rate requires a transformation and the use of the gradient series formula. Without further derivation, the present value of the depreciation tax shield is:

$$PV_{Depr} = \tau\left(\frac{TC}{N}\right)\left(\frac{1}{1+e_i}\right)\left(P/A,\left(\frac{-e_i}{1+e_i}\right), r', N\right)$$

Then the real levelized investment cost is:

$$c_I\left({}^{mills}\!/_{kWh}\right)=\frac{\left(TC-PV_{Depr}\right)\left({}^{\$}\!/_{kW}\right)\cdot 10^3\left({}^{mills}\!/_{\$}\right)}{(1-\tau)\cdot 8760\left({}^{hr}\!/_{yr}\right)\cdot\Phi}(A/P,r',N)$$

where Φ is the average capacity factor of the plant, which is defined as the ratio of the average load on the plant for a given period of time and the plant's rated capacity. The levelization procedure simply calculates a level series of cash flows that are equivalent to the adjusted investment cost and divides by the average number of hours of operation in a year to get the cost per kWh. The $(1 - \tau)$ term is necessary because revenues must be sufficient to cover the additional cost of income taxes.

Two additional costs are added to the levelized investment cost to get the total levelized capital cost: incremental capital expenditures and nuclear decommissioning costs. The levelization procedure is similar. To simplify the expression, incremental capital expenditures are treated as expenses instead of being added to the depreciable asset base. The error introduced by this approximation is not expected to be significant for reasonable values. Note that the two expenses added to the levelized investment cost do not have an income tax term because operating expenses are tax deductible.

$$c_{Cap}\left({}^{mills}\!/_{kWh}\right)=c_I+\frac{C_{Capx}\left({}^{\$}\!/_{kW-yr}\right)\cdot 10^3\left({}^{mills}\!/_{\$}\right)}{8760\left({}^{hr}\!/_{yr}\right)\cdot\Phi}+\frac{C_{Decom}(\$mm)\cdot 10^9\left({}^{mills}\!/_{\$}\right)\cdot(A/F,r',N)}{G(MW)\cdot 10^3\left({}^{kW}\!/_{MW}\right)\cdot 8760\left({}^{hr}\!/_{yr}\right)\cdot\Phi}$$

The effects of inflation

It is important to understand the effect that inflation has on the levelized capital cost so that results are not misinterpreted. If the overnight cost is specified in year 0 dollars, then all construction expenditures are made at lower price levels, assuming positive inflation. Thus, inflation has the effect of reducing the total cash expended during construction, and the longer the construction period and the higher the rate of inflation, the more the total expenditure decreases. This effect is more than counterbalanced by the cost of capital during construction. The nominal average cost of capital will never be below the rate of inflation and so all savings from early construction, and more, are lost to capital charges. Most likely, the average cost of capital is well above the rate of inflation and reducing construction time becomes a priority to avoid additional capital costs.

Another potential mistake is to note that increasing the rate of inflation in the WACC expression from Chapter 4 reduces the real WACC, holding all other values constant. While this is true, it does not reflect the realities of financial investments. In rough terms, investors expect payments that maintain the real value of their investment and compensate them for the use of the principal and for the risk that returns will not meet expectations, or in the case of bond holders, that the borrower will default on the payments. When the rate of inflation is high, nominal returns on debt and equity should adjust to maintain the real rate of return, keeping the real WACC in rough equilibrium.

Real levelized O&M cost

Operations and maintenance costs can be split into a fixed cost per kW-year and a variable cost per kWh. O&M expenses are tax deductible, so there is no adjustment for income taxes. In the base year, total O&M costs are:

$$c_{O\&M,0}\left({}^{mills}/_{kWh}\right) = \frac{C_{O\&M,f}\left({}^{\$}/_{kW-yr}\right)\cdot 10^3\left({}^{mills}/_{\$}\right)}{8760\left({}^{hr}/_{yr}\right)\cdot \Phi} + C_{O\&M,v}\left({}^{mills}/_{kWh}\right)$$

In the analysis, O&M costs are allowed to escalate at a specified real rate. If price escalation is zero, then the base year cost above is equal to the real levelized cost. Otherwise, an adjustment must be made to include the effect of price escalation.

$$c_{O\&M}\left({}^{mills}/_{kWh}\right) = (A/P, r', N)\sum_t \frac{c_{O\&M,0}(1+e'_{O\&M})^t}{(1+r')^t}$$

$$= (A/P, r', N)\cdot c_{O\&M,0}(1+e'_{O\&M})(P/A, e'_{O\&M}, r', N)$$

Real levelized fuel cost

Fuel costs are treated in a fashion similar to the treatment of variable O&M costs. Fuel costs are tax deductible and a real escalation rate can be specified. The heat rate, *HR*, of a plant is a measure of its thermodynamic efficiency and is defined as the amount of energy required to produce a kWh of electricity. In the case of nuclear power plants, a fee is collected for every kWh of electricity produced to cover future disposition of nuclear waste and is added to the real levelized fuel cost.

$$c_{Fuel,0}\left({}^{mills}/_{kWh}\right) = \frac{C_{Fuel}\left({}^{\$}/_{mmBTU}\right)\cdot 10^3\left({}^{mills}/_{\$}\right)}{10^6\left({}^{BTU}/_{mmBTU}\right)} HR\left({}^{BTU}/_{kWh}\right) + C_{NWF}\left({}^{mills}/_{kWh}\right)$$

$$c_{Fuel}\left({}^{mills}/_{kWh}\right) = (A/P, r', N)\sum_t \frac{c_{Fuel,0}(1+e'_{Fuel})^t}{(1+r')^t}$$

$$= (A/P, r', N)\cdot c_{Fuel,0}(1+e'_{Fuel})(P/A, e'_{Fuel}, r', N)$$

The imposed cost of a carbon tax can be added to the total real levelized cost to compare the costs of technologies in the face of government actions to curb carbon dioxide emissions. τ_{Carbon} can represent a direct tax on carbon emissions or the market price for emissions permits in a cap and trade system. It is specified as a constant value over the operating life of the plant in inflation-adjusted dollars. The cost of the tax depends on the carbon intensity of the fuel, measured in kilograms of carbon per mmBTU.

$$c_{Carbon}\left({}^{mills}/_{kWh}\right) = \tau_{Carbon}\left({}^{\$}/_{tonne-C}\right)\left(\frac{mills-tonne}{\$-kg}\right)\cdot\frac{\alpha\left({}^{kg}/_{mmBTU}\right)}{10^6\left({}^{mmBTU}/_{BTU}\right)}\cdot HR\left({}^{BTU}/_{kWh}\right)$$

10 Appendix C: Merchant Plant (MP) Valuation Model

The cash flows to equity approach to power plant valuation avoids the financing assumptions inherent in the using a weighted-average cost of capital. Specifically, the method captures the effect of realistic debt service obligations on the cash flows available to plant equity holders and treats corporate income tax payments explicitly. Distinct interest rates can be applied to individual cost items, which is not possible in the application of the revenue requirement method described in Appendix B. The merchant plant (MP) model, following this approach, also allows further investigation into the economic performance of power plants under different electricity market assumptions and provides short-term financial indicators that are crucial to financial health and have bearing on investors' perceptions of the firm.

The MP model is simpler conceptually than the RR model, but is not amenable to closed form expressions and therefore requires the use of a spreadsheet. The valuation problem takes the form of a series of corporate financial statements, one for each year of plant construction and operation. All project cash flows, including revenues from electricity sales and payments to creditors, are registered in the year in which they occur, and any funds remaining after all payments have been made are discounted to the present at the assumed cost of equity. For this analysis, a single cost of equity is applied over the life of the plant. For a discussion of why this may not be entirely appropriate, see Brealey and Myers (2003).

The spreadsheet calculation lays out nominal cash flows and the net cash flows available for equity distribution are discounted at the nominal cost of equity. To produce a real levelized cost, the price of electricity includes an escalation factor equal to the rate of general inflation; the price at the time the plant enters operation is the real levelized cost. The spreadsheet model can also accept electricity price trends beyond a simple levelized cost, allowing for an evaluation of profitability in different market conditions. When solving for a levelized cost, the model requires two constraints to be met. First, the return on equity must exceed a given value, and second, all debt obligations must be met in each year of operation. If revenues are insufficient to cover debt payments, the levelized cost is increased, which may result in returns to equity holders that exceed the specified requirement. In this case, the levelized cost is no longer identical to the annual equivalent of the NPV expressed on a per-kWh basis.

Figure 10-1 is a sample of the spreadsheet used in the MP model. A summary of the cost calculations follows, with particular emphasis on those items that differ from the revenue requirement approach.

($million)											
Year	-5	-4	-3	-2	-1		1	2	3	4	5
Cost of electricity (cents / kWh)						6.16	6.34	6.54	6.73	6.93	7.14
- Electricity real price escalation						0.00%					
Revenues from electricity sales							$473	$487	$502	$517	$532
Operating expenses											
Fuel							($32)	($33)	($34)	($35)	($36)
Nuclear waste fund							($8)	($8)	($8)	($8)	($9)
Carbon emissions tax							$0	$0	$0	$0	$0
Non-fuel operations and maintenance											
- Fixed							($60)	($62)	($64)	($66)	($68)
- Variable							($3)	($3)	($3)	($3)	($3)
Associated general and administrative costs							$0	$0	$0	$0	$0
Decommissioning sinking fund							($12)	($12)	($12)	($12)	($12)
(Fund balance)							$12	$25	$38	$52	$67
Capital additions and refurbishment							($19)	($19)	($20)	($20)	($21)
Total operating expenses							($134)	($137)	($141)	($145)	($149)
Pre-tax operating income							$339	$350	$361	$372	$383
Depreciation							($65)	($123)	($111)	($100)	($90)
(Net fixed assets)						$1,295	$1,230	$1,107	$996	$897	$807
Interest charges							($68)	($66)	($63)	($60)	($57)
Taxable income before adjustment							$206	$161	$187	$212	$237
Net operating losses carried forward							$0	$0	$0	$0	$0
Taxable income							$206	$161	$187	$212	$237
Income tax liability							($78)	($61)	($71)	($81)	($90)
Production tax credit							$0	$0	$0	$0	$0
Income Taxes							($78)	($61)	($71)	($81)	($90)
Net income							$128	$100	$116	$131	$147
Cash flows from operating activities							$192	$223	$228	$231	$236
Cash flows from investing activities											
Construction expenditures	-$99	-$267	-$339	-$283	-$111	$1,099					
Cash flows from financing activities											
Long-term debt issuances	$59	$160	$204	$170	$67						
Common stock issuances	$40	$107	$136	$113	$45						
Long-term debt redemptions							($31)	($34)	($37)	($40)	($43)
Net cash flow	$0	$0	$0	$0	$0		$161	$189	$190	$191	$193
Investor Returns											
Stockholders' cash flow	($40)	($107)	($136)	($113)	($45)	$0	$161	$189	$190	$191	$193
Creditors' cash flow	($59)	($160)	($204)	($170)	($67)	$0	$100	$100	$100	$100	$100
Total investment cash flow	($99)	($267)	($339)	($283)	($111)	$0	$261	$289	$290	$291	$293
After-tax return on equity						23.6%					
Total return on all long-term debt						8.3%					
Return on investment						17.1%					
Pre-tax debt coverage ratio							3.40	3.50	3.61	3.72	3.84

Figure 10-1: Example of the MP model spreadsheet

Pre-tax operating income

The only source of revenue in the spreadsheet model is the sale of electricity. Payments for operating reserve services or secondary products are not included. The quantity of electricity produced is determined by the rated capacity of the plant and its average capacity factor, although a tailored output profile could be incorporated easily. If it is not economic to run the plant in a given year, then there will be no output and thus no revenue stream.

Operating expenses are similar to those included in the RR model: fuel, operations and maintenance (O&M), a mandatory nuclear waste fee and funding for decommissioning in the case of nuclear power plants, and any expenses related to carbon emissions regulation, in the form of carbon taxes or emissions permit purchases. Incremental capital additions and refurbishments to maintain the safety and performance of the plant are treated as operating expenses in the model, though in reality they should be capitalized and depreciated over a period of many years. As opposed to the RR model, where the sinking fund for nuclear decommissioning accrued interest at the (real or nominal) weighted-average cost of capital, the MP model allows specification of a separate interest rate for the sinking fund, which presumably is lower than the firm's cost of capital due to financial assurance mechanisms required by the Nuclear Regulatory Commission. The annual pre-tax operating income is the difference between operating revenues and operating expenses. It is also referred to as earnings before interest, taxes, depreciation, and amortization, or *EBITDA*.

Asset depreciation

Unlike the RR model, which assumed straight-line depreciation, the MP model allows for accelerated depreciation of assets using the IRS-standard Modified Accelerated Cost Recovery System (MACRS) for calculating the annual tax liability. Depreciation expenses are deductible from corporate income taxes and therefore provide the plant owner with a valuable tax shield. A constant percentage of the undepreciated asset base can be expensed in each year, making (non-cash flow) depreciation expenses larger in the early years. This is referred to as the declining balance method. The recovery period, or the time over which the plant is depreciated, is determined by the IRS property classification and is shorter than the 30 years assumed in the WACC model, which also has the effect of front-loading the depreciation tax shield. The first year depreciation expense is reduced by half from what would result using a simple declining balance calculation in accordance with the IRS's half-year convention. For more information on MACRS and asset depreciation, see IRS Publication 946, *How To Depreciate Property.*

IRS rules require that interest on debt used to produce real property be capitalized, or added to the property value, and recovered over the specified recovery period. The MP model capitalizes interest during construction in accordance with the law, in contrast to the RR model, which capitalizes both the interest on debt and an imputed interest on equity financing during construction. The smaller depreciable asset base in the MP model reduces the value of the resultant income tax shields.

Payments to creditors

The primary difference between the RR model and the MP model is the treatment of debt financing. In the MP model, an interest rate can be specified for the construction period that is different than the rate during operation. The two rates represent two separate debt issues. A construction loan or equivalent debt security is used to raise funds during construction. Once the plant commences commercial operation, the loan is refinanced by issuing corporate bonds or some other form of debt. The interest that accrued during construction is included in the principal value of the new issue.

The MP model allows the analyst to specify the maturity of bond. This is the single most important difference between the MP model and the RR model because by requiring that debt be paid off before the plant reaches the end of its life, cash flows to equity holders are postponed, reducing their present value. The model assumes a mortgage-style payment schedule of equal annual payments over the term of the debt, representing a sinking fund for redeeming the issue in the case of a corporate bond. The payments made to the sinking fund can be delayed by specifying a grace period, which may be important for a project's financial health in the first year of operation. In the extreme case, a grace period equal to the bond maturity mimics a coupon bond where the face value is repaid at maturity. As always, interest payments are deductible from taxable income.

Financing fees are not included in the model, nor is there a debt service reserve fund, which is sometimes used to provide additional assurance to creditors that the company will not default on its obligations. There is, however, a debt coverage requirement. The pre-tax operating income must exceed a specified multiple of the total annual debt service obligation. If this constraint is not met, and the model is solving for a levelized cost, then the price of electricity must be raised until the coverage ratio is satisfied.

Income taxes

Corporate income taxes are paid on operating income net of allowed (non-cash) depreciation expenses and interest payments on debt, if the net value is positive.

Taxable income = Pre-tax operating income – depreciation – interest charges

The model allows net operating losses to be carried forward to reduce the income tax liability in future tax years. The tax payment is equal to the product of the marginal corporate tax rate and taxable income net of any losses carried forward. A single, flat tax rate is used to represent the combined tax liability to all jurisdictions with authority to tax.

The net income provided by the power plant is then the pre-tax operating income, or EBITDA, minus the depreciation and interest expenses and income tax payments.

Net Income = EBITDA – depreciation expense – interest expense – income taxes

The net income, or net earnings, includes the non-cash depreciation expense and is therefore not a measure of actual cash flows. It is, however, important as an accounting convention for measuring the ongoing financial health of the company. More important for project valuation are the net cash flows from operating activities. Net cash flows include only actual transfers of cash and are equal to electricity revenues minus the actual cash expenditures necessary to run the plant. In this case,

Net cash flows from operating activities = EBITDA – Interest payments - Income taxes
=Net Income + Depreciation expense

It is the net cash flows from operations that provide returns on the equity investment in the plant.

Cash flows from financing and investment activities

Before calculating investor returns and valuing the project, the cash flows from financing and investment activities need to be included. In the case of a single power plant project, the construction expenditures constitute the only investment cash flows. The direct cost of construction is allocated to the years comprising the construction period in the same way as was described in Appendix B, with the caveat that the RR model discounts real, or constant-dollar cash flows, and the MP model works with nominal cash flows. The allocation of real expenditure is identical but the entries in the MP model must not be adjusted for inflation. Cash flows from operations net of investments in plant and equipment for future growth is often called *free cash flow*.

The handling of financing cash flows necessarily differs from the RR model, as debt and equity issues are treated separately. During construction, expenditures are funded through debt and equity issues in the specified proportions. Interest on debt accrues (and is therefore not a cash flow) at the construction loan interest rate until the start of commercial operation, at which time the entire debt, including accrued interest, is refinanced and debt payments begin. Interest on debt is included in the operating cash flows described above. Payments to retire the debt principal, whether through a sinking fund or other mechanism, are treated as financing activities.

Any net cash flows remaining after investment activities and debt redemption belong rightfully to the owners of the project. These funds could be paid out as dividends or retained for future investments. The model does not make the distinction between dividends and retained profits but the calculation of returns assumes that the profits are distributed to equity holders immediately.

Calculation of investor returns and levelized cost

Once all forecast cash flows for the project are identified, determining the returns to investors is a simple matter of computing the internal rate of return (IRR) of individual cash flow streams. For equity owners, the stream consists of negative cash flows from common stock purchases during construction (the inverse of the company's positive cash flows from stock issuance), and net cash flows during plant operation. The total return to investors can be computed by counting all cash flows during construction as negative values and including in the operating period net cash flows and (positive) interest payments and bond redemption (sinking fund) payments.

Computing the levelized cost of the project requires iteration in the spreadsheet on the price of electricity until two constraints are met. As the electricity price is increased, the IRR of the equity cash flow stream increases as more net cash flow is available to the project's owners. The equity IRR must exceed the specified nominal cost of capital, or *hurdle rate*, for the project to be viewed as a viable investment. Increasing the price of electricity also improves the debt coverage ratio, as pre-tax operating income grows while debt obligations remain fixed. The coverage ratio in each year must exceed the specified minimum requirement to give investors some assurance that the company will not default on its obligations. Which of these constraints is binding depends on the capital structure and cost structure of the project. If desired, the spreadsheet model can compute variants of the levelized cost, where electricity prices are assumed to escalate at a rate different than the general inflation rate, or where the initial price of electricity is fixed and the minimum escalation rate is determined so that both constraints are met.

Early termination decision

A final feature of the MP model is its ability to detect conditions where continued operation of the plant is uneconomic and to cease production to avoid operating losses. While it is a simplistic representation of the operating decision, it nonetheless provides a better measure of the true economic value of a project under conditions where costs escalate significantly faster than revenues. The model is not forward-looking in the sense that future recovery, or the prospect of future recovery, might force a plant to run when it is uneconomical to do so. Rather, the assumption, based on the nature of the model design, is that once the operating costs exceed revenues, this situation will persist and the plant will have lost all value. (The model assumes no salvage value for the plant.) In that case, the model ceases production and, along with it, all revenues and operating costs. If non-operating fixed charges remain, they must be paid with retained profits.

A more detailed representation of the early termination decision is not warranted for the level of analysis that this model supports. The primary purpose of including the capability was to avoid penalizing natural gas plants for continued operation under assumptions of high fuel price escalation, when fuel costs reach unrealistic levels. Comparing levelized cost over different time spans also introduces additional analytical complications, but this is not considered to be critical for the present analysis.

11 List of References

Bodie, Zvi, Alex Kane and Alan J. Marcus (1999), *Investments*, 4th Ed., Irwin/McGraw-Hill, Boston, MA.

Brealey, Richard A. and Stewart C. Myers (2003), *Principles of Corporate Finance*, 7th Ed., McGraw-Hill/Irwin, Boston, MA.

Dixit, Avinash K. and Robert S. Pindyck (1994), *Investment under Uncertainty*, Princeton University Press, Princeton, NJ.

Electric Power Research Institute (EPRI) (1986), *TAG™ - Technical Assessment Guide Volume 1: Electricity Supply - 1986*, Palo Alto, CA.

Electric Power Research Institute (EPRI) (1987), *TAG™ - Technical Assessment Guide Volume 3: Fundamentals and Methods, Supply – 1986*, Palo Alto, CA.

Energy Information Administration (EIA), U.S. Department of Energy (1986), *An Analysis of Nuclear Power Plant Construction Costs*, DOE/EIA-0485.

Energy Information Administration (EIA), U.S. Department of Energy (2002), *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001).

Energy Information Administration (EIA), U.S. Department of Energy (2003), *Annual Energy Outlook 2003*, DOE/EIA-0383(2003).

Gardner, Douglas T. and J. Scott Rogers (1999), "Planning Electric Power Systems Under Demand Uncertainty with Different Technology Lead Times," *Management Science*, Vol. 45, No. 10.

Hyman, Leonard S., Andrew S. Hyman, Robert C. Hyman (2000), *America's Electric Utilities: Past, Present and Future*, 7th Ed., Public Utilities Reports, Inc., Vienna, VA.

Joskow, Paul L. (1996), "Introducing Competition into Regulated Network Industries: From Hierarchies to Markets in Electricity," *Industrial and Corporate Change*, Volume 5, No. 2.

Joskow, Paul L. (2000), "Deregulation and Regulatory Reform in the U.S. Electric Power Sector," in *Deregulation of Network Industries: The Next Steps* (S. Peltzman and Clifford Winston, eds.), Brookings Press.

Joskow, Paul L. (2003), "The Difficult Transition to Competitive Electricity Markets in the U.S."

Joskow, Paul L. and Richard Schmalensee (1983), *Markets for Power: An Analysis of Electric Utility Deregulation*, MIT Press, Cambridge, MA.

Kadak, Andrew C. (2000), "Modular Pebble Bed Reactor," March 22, 2000 presentation, MIT/INEEL.

MIT Study on the Future of Nuclear Power (2003), *The Future of Nuclear Power: An Interdisciplinary MIT Study.*

Park, Chan S. and Gunter P. Sharp-Bette (1990), *Advanced Engineering Economics*, John Wiley and Sons, Inc., New York, NY.

Performance and Innovation Unit, U.K. (PIU, 2001), "The Economics of Nuclear Power: PIU Energy Review Working Paper," available at http://www.number10.gov.uk.

Skantze, Petter L. and Marija D. Ilic (2001), *Valuation, Hedging and Speculation in Competitive Electricity Markets: A Fundamental Approach*, Kluwer Academic Publishers, Boston, MA.

Talbot, David (2002), "The Next Nuclear Plant," *Technology Review*, January/Februry 2002.

Teisberg, Elizabeth Olmsted (1994), "An Option Valuation Analysis of Investment Choices by a Regulated Firm," *Management Science*, Vol. 40, No. 4.

Viscusi, W. Kip, John M. Vernon, and Joseph E. Harrington, Jr. (2000), *Economics of Regulation and Antitrust*, MIT Press, Cambridge, MA.