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Evaluation Methods in Competitive Bidding for Electric Power

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EVALUATION METHODS IN COMPETITIVE BIDDING FOR ELECTRIC POWER

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June 1989

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

EXECUTIVE SUMMARY

Background

Competitive bidding for new electricity generation is a rapidly growing phenomenon. A number of utilities have completed auctions for long-term power contracts with private suppliers, and more are being proposed. Yet despite all of this activity, there has not been any systematic analysis of the design choices posed by this process. Are these procedures economic? What biases are built into the process? How are various objectives traded off against one another in the implementation of competitive bidding?

In this report we undertake a systematic analysis of some of the competitive bidding procedures that have been used or are being proposed at the state level. We take no position on the larger political debate surrounding this process. These policy issues, raised principally by initiatives of the Federal Energy Regulatory Commission (FERC), address the scope and appropriateness of competitive bidding. The FERC Notices of Proposed Rulemaking argued that competitive bidding should not only be allowed for Qualifying Facilities (QFs) under PURPA, but should also be expanded to include a new class of private producers called Independent Power Producers (IPPs). Various interests have argued this proposition. Some have endorsed it; some have opposed it; and some have suggested that bidding is fine for QFs, but should not include IPPs. Regardless of how these questions are ultimately settled, however, the current reality is that competitive bidding in several forms is currently being undertaken. To understand this phenomenon in practice, it is useful to analyze it systematically in detail.

Constructing a competitive bidding procedure requires accounting for complex pricing, performance and contractual issues. Utility planners have experience analyzing the multi-attribute nature of power projects, but the bidding environment adds a new dimension. With bidding, the attributes must be unbundled, valued explicitly and independently, and traded-off in arms-length transactions. As utilities experiment with making these evaluations, it is inevitable that approximations will be used that affect technologies and bidders differently.

We find that the bidding systems in use or under advanced stages of review differ substantially from one another. The most fundamental distinction involves the approaches taken by utilities to scoring and ranking projects. At one extreme, some utilities have adopted linear self-scoring point systems. These systems provide bidders with explicit evaluation sheets where each relevant feature receives a specified number of points depending on the project characteristics. Bidders add up their own scores and the utility verifies the data and selects winners based on the highest scores. In contrast, other utilities only reveal bid evaluation criteria in general terms. In these systems the rank of any bid cannot be verified after the fact, and the utility possesses information about the evaluation process that bidders do not. We call the first approach an "open" system and the second approach "closed". Open systems emphasize the perception of fairness in the evaluation; closed systems emphasize flexibility for the utility.

Bidding systems also differ in the "nominal" weights assigned to price and other factors; these weights are provided by the utility in its solicitation. For example, dispatchability, the be operating in the future when payments are below avoided costs. In effect, customers would be getting repaid in later years for their "loan" in the early years of operation. Projects with relatively low risks might require interest rates that are slightly above typical utility bond rates to reflect the limited operating history of QFs and IPPs. Riskier projects might require interest rates over 15%. For instance, the last public offering of debt made by Public Service of New Hampshire before its bankruptcy required a 17-1/2% coupon in the spring of 1987. We found that for a particular representative project evaluated in the Boston Edison framework, the implicit loan interest rate ranged from 25-65%, depending on the security offered. This is unrealistic in light of risk premia required on other loans. We also tested this same project using the proposed Niagara Mohawk Power evaluation system and found that the implicit interest rate ranges from 13-16%, which is more reasonable.

Simulating Dispatchability

We simulated the auction conducted by Virginia Power in 1988. This competition virtually required dispatchability by bidders, and evaluated bids in a "closed" system. A priori, linear self-scoring is economically inefficient in this situation, because it is impossible to specify in advance the value of different degrees of dispatchability. In this type of large-scale auction, the value of one bid depends upon all of the other bids. In this case the interdependence is greater than the simple distinction between nominal and real linear weights. The amount that any project could be expected to operate depends on the cost characteristics of all competitors. In small-scale auctions, where interactions are potentially negligible, linear self-scoring can be acceptable. However, the interactions among projects are of fundamental importance in situations in which large resource additions are being evaluated (i.e., where more than 10% of the system is being acquired in one solicitation). We structured our simulation as an optimization using the EGEAS model to select from an artificially constructed distribution of bids. We then examined various ways that the utility's announced preference for coal-fired power projects could be incorporated in this framework. Even though optimization does not yield a simple ranking of project economics, we found that it was just as amenable to accounting for non-price factors as the linear self-scoring systems.

Open vs. Closed Systems

Achieving the desirable efficiency properties of the Virginia Power type approach requires a "closed" evaluation system. A complex computer program is required, which must be used with a lot of data and imagination. However, at the present time, the "open" systems represent the dominant trend in the design of evaluation systems. One reason for the prevalence of "open" self-scoring is the underlying background of distrust between utilities, private suppliers and state regulatory agencies. This distrust goes back to the history of PURPA implementation and the planning problems experienced by utilities during the last 15 years. "Open" systems lay out all value judgments explicitly so that there can be no claim of hidden bias or prejudice in the actual scoring. The process is automatic and auditable. In a "closed" system, the utility regulator is implicitly granting substantial discretion to the utility, and keeping information from the bidders.

1. INTRODUCTION

Competitive bidding for new electric generation by private power producers is becoming an increasingly important feature of utility resource planning and represents a major departure from the historical practices of the electric utility industry in which new generating resources were constructed by vertically-integrated utilities. Bidding in the electric supply context originated as a reform of the PURPA process for purchasing power from certain private producers. Some states and utilities have designed their bidding systems to allow all potential suppliers to compete, including Independent Power Producers, a class of potential suppliers that are privately-owned but do not meet the tests for qualifying status under PURPA, and even firms that offer demand-side reductions. Competitive power procurements promise to fundamentally reshape the market for power technologies.

In this study, we examine the bidding processes being used or proposed by utilities to evaluate bids made by producers. The design of bid evaluation systems is a challenging task because it requires an explicit externalization of many aspects of utility planning as well as treatment of the issues associated with long-term contracting. For example, contracting for new generating capacity requires utilities to unbundle various attributes of power projects that have not been priced in the market previously (e.g., operating characteristics, project viability, and price risks). This is a formidable and qualitatively new problem for utility planners. Moreover, the practical demands imposed by the need to have systems that are workable and reasonably simple means that short-cuts, approximations, and rules of thumb will be developed. In some cases, this can lead to unintended biases in bidding systems. In this study, we focus our analysis on those non-price factors that particularly affect the prospects for capital-intensive technologies.

In Chapter 2, we review the origins of competitive bidding and discuss three background questions: (1) what is the nature of competitive bidding for new electricity capacity? (2) why has bidding appeared and why should we study it, and (3) where is bidding being practiced? In Chapter 3, we describe current and proposed bid evaluation systems and introduce the basic conceptual approaches that have emerged to date. Chapter 4 focuses on several theoretical issues that arise in bid evaluation: the treatment and pricing of various types of risk and the determination of the economic value of non-price factors. Evaluation of the non-price factors of proposed projects is complex and unprecedented. We discuss the treatment and allocation of risks involved in project failure and fuel price uncertainty. We also develop an economic framework that can be used to evaluate front-loaded bids, which has proven to be a key issue for private developers, utilities and ratepayers. In Chapter 5, we discuss methods for evaluating the value of dispatchable power. Dispatchability is one of the most important operational features that private suppliers can provide to electric utilities. We analyze how Pacific Gas & Electric and Virginia Power have incorporated dispatchability into their proposed bid evaluation systems. Virginia Power's approach is unique and less transparent to bidders, thus we conduct a simulation of their existing system and recent large-scale procurement. In Chapter 6, we attempt to contrast the various approaches used by utilities by evaluating them against a standard set of hypothetical bids from eight generic projects. This exercise illustrates the importance of

2. THE ORIGINS OF COMPETITIVE BIDDING AND THE PROSPECTS FOR CAPITAL-INTENSIVE TECHNOLOGIES

In this chapter, we briefly summarize the recent history of the U.S. electric utility industry and discuss reasons why state public utility commissions (PUCs) and utilities are establishing bidding systems to procure new generation resources. Readers that are familiar with this background will find it more productive to proceed to Section 2.3 where we describe the challenges that bidding systems pose for utility planners and identify key design issues that affect capital-intensive technologies.

2.1 Historical Overview of the Electric Utility Industry

For most of its history, the electric utility industry has consisted primarily of vertically integrated firms that built central station power plants and bulk power transmission to realize scale economies in generation and transmission. The utility retained ultimate financial and managerial responsibility, although these construction projects were contracted, in whole or in part, to private engineering firms. The utility's financial earnings were determined to a great extent by the successful development of its generation projects. The basic regulatory mechanism that governed the industry was an obligation to serve on the part of the utility, and the recovery of investment costs through rate adjustments administered by a public utility commission.

The relative influence and contribution of private unregulated firms in the U.S. power industry has changed quite dramatically over time. Prior to the 1920s, almost half of total U.S. generating capacity was located at industrial sites (OTA, 1983). Figure 2-1 illustrates the dramatic decline in the relative contribution of private production that occurred after the industry became regulated. The dominant reason for the historic decline was the increasing efficiency of central station production. Electric prices declined in real terms from 1940 until about 1970. This price situation changed during the 1970s as the utility industry was beset by dramatic increases in fuel costs as well as increasingly stringent environmental regulation (e.g., Clean Air Act of 1970 and its 1977 Amendments). The oil price shocks increased already high levels of inflation, which resulted in higher construction and financing costs for power plants (DOE, 1983). The overall effect of these developments resulted in increased electric prices (in real terms) and demand growth slowed dramatically.

PURPA was passed during this tumultous period and fundamentally altered the market position of private production. PURPA required that utilities purchase electricity from a class of producers designated as Qualifying Facilities (QFs) under pricing arrangements governed by a concept known as the utility's "avoided cost." State regulators were delegated the responsibility for implementing the avoided cost principle. The federal government conferred QF status on applicants that met certain cogeneration efficiency tests or used renewable energy for projects less than 80 MW. QF status exempted the supplier from public utility regulation.

PURPA has been extremely successful in stimulating cogeneration and small power production. During the 1980s, about 13,000-15,000 MW of non-utility capacity were built, although there were significant regional variations in non-utility capacity additions (Griggs, 1988). There was an enormous outpouring of private production in states that had a favorable regulatory climate as well as significant potential for cogeneration. For example, it is estimated that QFs will represent about 15-20% of the total generation of California's two largest utilities by the early 1990s. Significant levels of QF development also occurred in Texas, New Jersey and Maine. In contrast, some regions with low avoided costs had little QF development.

PURPA was not an unqualified success, as difficult implementation problems arose, particularly in those states with significant levels of QF development. In response, a few utilities and PUCs began experimenting with the use of competitive bidding procedures to ration the supply of private power development and to select the most beneficial projects. PURPA never explicitly envisioned an auction-like process for allocating new capacity contracts among potential suppliers.[1] However, PURPA did not explicitly forbid bidding. Substantive legal arguments have been raised on the issue of whether bidding is a legitimate implementation strategy under PURPA (Griggs, 1988). Some PUCs have forged ahead, while others were unwilling to undertake bidding experiments because of these ambiguities.

In March 1988, the Federal Energy Regulatory Commission as part of its review of PURPA issued three Notices of Proposed Rulemaking (NOPRs): administrative determination of full avoided costs (ADFAC), regulations governing competitive bidding programs, and regulations governing independent power producers (FERC, 1988a,b,c). The FERC NOPRs actually broadened the areas of debate by including utilities as potential participants in bidding as well as a new class of private producers. Independent Power Producers (IPPs) are private suppliers that do not meet the tests for QF status.[2] Under FERC's proposal, IPPs would be subject to only minimal regulation. FERC also proposed that states be allowed to implement "all-sources bidding" in which IPPs would be included as well as QFs. At the current time, FERC has not issued final rules on any of the three rulemakings; FERC's recommendations on IPPs were particularly controversial.

While FERC deliberates these issues, an increasing number of states and utilities continue to propose and implement bidding systems for new generating capacity. Table 2-1 summarizes current experience of utilities with electric power auctions, and includes data on the amount of capacity solicited by utilities as well as response by suppliers, as indicated by the amount of capacity offered. Initial experience with power auctions suggests that there is a large pool of private suppliers willing to provide capacity at current avoided costs. Thus far, the capacity offered by private producers has often been 10-20 times greater than the utility's capacity requirements. In addition, a number of utilities, most of which are implementing PUC orders in New York and New Jersey, have recently proposed bidding systems and plan to hold auctions during the next several years (Table 2-2). Many of these utilities are proposing an integrated auction in which both supply and demands resources compete to fill the defined resource need.

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[1] Note that under PURPA both winning and losing bidders may still sell power to the utility. Winning bidders receive both the capacity and energy components of the utility's avoided costs, while losing bidders may receive only the energy component of the utility's avoided cost.

[2] IPPs are defined as entities that are selling from facilities that are not regulated on a cost-of-service basis, that do not control transmission facilities essential to the buyer, and, if they are a franchised utility, are selling to buyers outside their retail service territory.

2.2 Why Are PUCs Establishing Competitive Bidding Systems for Electric Power?

Recounting the events leading up to the appearance of competitive bidding does not explain why it has occurred. We would argue that the popularity of competitive bidding is strongly linked to the failures of central station power plant construction in the last ten years as well as problems associated with implementing PURPA. The changes in the business environment of the classic integrated utility firm produced many cases of high-cost power plants that came into service during a period of excess capacity. Some of the most notable examples involved nuclear plants that experienced licensing problems, cost overruns, and substantial delays. In some cases these projects were cancelled at substantial cost. In other cases, delays kept such projects out of operation even where there was substantial demand. The response of state regulators was to disallow and/or defer cost recovery. The financial health of the affected utilities was seriously impaired as dividends were reduced and stock prices fell; one utility has filed for bankruptcy.

Utility management has become averse to risky generation construction as a result of the perception that regulation has become hostile. In such an environment, utility's are inclined to minimize investment. Thus, risk avoidance is expressed increasingly by utility executives as an "anti-capital" bias. For example, FERC, in its analysis supporting the NOPRs, argued that currently there is an imbalance between risks and rewards for the utility industry, which means that utilities have strong incentives to minimize their capital expenditures (FERC, 1988d). These views are also expressed in the popular utility trade press as well as in recent academic literature, and run counter to the more conventional view that the classic integrated utility firm over-invested in capital-intensive technology, the so-called "Averch-Johnson" effect (Chao et al, 1984; Newberg and Gilbert, 1988). In the 1960s, when the theory of utility over-investment was first articulated, profitability conditions were favorable to capital-intensity. With the economic changes in the 1970s and 1980s, this was no longer true. Thus, the perception of regulatory hostility to traditional central station power plant construction has made private power production an attractive alternative because the risks of construction cost overruns, licensing delays, and financing problems are transferred from the utility to the private supplier.

In addition, the avoided cost framework of PURPA proved to be a fairly blunt instrument when it came to the subtleties of long-range power system planning. Avoided cost is a "posted price" system under which the utility is obliged to purchase from any and all suppliers. Those states which sought to encourage QF suppliers established long-term contracts based on forecasts of avoided costs. Long-term contracts greatly facilitate private production by reducing financing uncertainties. In California, where such contracts were standardized with few options for the purchaser to tailor terms to their needs, the greatest supplier response was forthcoming.

The California utilities have argued that the magnitude of the supplier response created major planning and operational problems. The open-ended nature of these QF contracts introduced substantial uncertainty about how much power would ultimately be developed. The operating characteristics of the QF projects became increasingly ill-matched to power system requirements. The obligation to purchase provision of PURPA and lack of sufficient time-differentiation in purchase price meant that QF output did not need to follow system load variations. This created a problem during minimum load periods when inexpensive energy resources had to be curtailed in favor of higher cost QF contractual obligations.

projects that were more under the control of the utility dispatcher (i.e., ''dispatchable'' power) would lower costs to the utility compared to projects with contracts that require the utilities to purchase all power (i.e.,''must take''). Dispatchability or the ability to follow fluctuations in utility system loads is valuable to the utility. However, even the more sophisticated methods of traditional utility planning do not yield explicit measures of this value. The value of load following is implicitly incorporated in the production simulation/system optimization studies conducted by generation planners. The outcome of such studies would be a recommendation about favored projects, but not a menu of values attached to particular degrees of dispatchability. Such "intermediate" results had no value for planning within the firm, but they are now essential to comparing bids that are differentiated along this dimension.

Although resource planners have not explicitly unbundled the long-range value of dispatchability, utility operators have confronted similar problems in the short run. Many wholesale transactions occur between utilities that are differentiated by delivery characteristics. The premium associated with different degrees of dispatchability can be estimated from market transactions. For example, Bonneville Power Administration has made transactions that are differentiated by degrees of buyer control. Similarly, power pools also differentiate service to members. Nonetheless, this information is short-term in nature and is not immediately transferrable to the long-term planning context. To evaluate long-term contracts, there must be estimates of long-run value and utilities must develop these estimates analytically in the absence of market data.

The analytic problems associated with valuing benefits are even more difficult for "nontraditional" attributes. For example, project viability is a particularly difficult issue. Developing a power project either under regulation or as a private supplier is a complex and uncertain task. The problems include both financing and permitting. The failures of central station construction during the last ten years involved both issues. These problems are not any easier for the private developer. Bid evaluation systems typically include measures of project viability, because an ideal project is worthless if it never materializes. Despite the desirability of measuring the likelihood of success, there is little evidence that current methods discriminate reliably among projects.

In summary, bidding systems need to be studied because of the analytic challenges involved in measuring and unbundling the complex attributes of power projects. Moreover, the practical demands of workability impose limits on the complexity of bid evaluation systems. It is inevitable that approximations, short-cuts, and rules of thumb will be developed to create tractable systems. As we analyze the methods being used or proposed to measure various non-price factors, it will become clear that bid evaluation systems can have substantial biases, intended or not, which affect the prospects for capital-intensive technologies.

2.4 What Aspects of Competitive Bidding Influence Capital Intensive Technologies?

The experiences that led to the relative decline of regulated central station power plant construction are likely to influence the environment in which competitive bidding is adopted and implemented. We characterize this environment as risk-averse. In particular, what is being avoided is uncertainty in the short-run; longer-run risks may actually increase by excessive concern with eliminating short-runs risks. Nonetheless, in the current environment, by transferring

The contract terms offered by utilities in their competitive bidding systems can affect these constraints. "Front-loading" is one approach that is used to ease the barriers to capital-intensive projects and involves pricing above avoided cost in the short run, in exchange for lower prices in the long run. We discuss this issue in some detail in the next two chapters. Bidding systems that forbid this practice, in the interest of avoiding risk to ratepayers, in effect, create a de facto bias in favor of low capital cost technologies. Not surprisingly, utilities have not adopted a uniform approach on the issue of front-loaded bids. In all cases, the supplier's financing need are considered and traded off against the risk perceptions of utilities and their regulators, although this balancing process is seldom made explicit.

3. COMPARISON OF BID EVALUATION SYSTEMS: TREATMENT OF NON-PRICE FACTORS

3.1 Overview

Determining the economic value of non-price factors is probably the most difficult problem that utilities confront in designing competitive bidding systems for long-term power contracts. Implicitly or explicitly, a bid evaluation system must take the price and non-price attributes of an offer and reduce them to a common measure, a score by which the decision to accept or reject is made. In this chapter, we examine the range of techniques that have been proposed or applied to this problem. Our approach is primarily descriptive and comparative rather than normative (normative questions are discussed in Chapters 4 and 5).

We compare the bid evaluation systems adopted or proposed by four utilities: Virginia Power (VP, 1988), Boston Edison (BECo, 1988a), Niagara Mohawk Power Company (NMPC, 1988a), and Orange and Rockland Utilities (ORU, 1988). We chose these companies because their bidding systems are similar enough to allow comparison, but also sufficiently different so that contrasts are informative. These utilities encompass a range of operating characteristics, economic environments and regulatory regimes; all of which influence their design choices. These four systems all share one fundamental design characteristic: the use of weights to trade off one feature against another. We also describe two other proposed bidding systems that are quite different conceptually: the scheme adopted by the California Public Utilities Commission (CPUC) and Consolidated Edison Company's (Con Ed) proposal for an integrated supply- and demand-side competition. The CPUC proposes a radically different framework, which is based primarily on a system of prescribed constraints rather than multi-attribute weights (CPUC, 1986, 1987, 1988). Con Ed's bidding system is unique because it does not assign an explicit weighting to non-price features initially (Con Ed, 1988).

3.2 Bidding Systems of Four Utilities

In March 1988, Virginia Power (VP) issued a Request for Proposals (RFP) that solicited bids from Qualified Facilities and independent power producers for 1750 MW of capacity to be delivered by 1994. VP's installed capacity in 1988 was approximately 12,000 MW and the utility purchased about 1500 MW under contract. VP projects that its peak loads will grow at a rate of 3% per year through 1994 to 13,613 MW from current levels (11,300 MW). Virginia Power's RFP thus represents about a 15% expansion of its system, which is a large increment by any definition.

The bidding systems for the other three utilities represent their proposed approach, which at the time of our study, had not received final review and approval from the respective state PUCs. Thus, the final RFPs issued by the utility may differ in some respects from these initial proposals because State regulatory commissions can be expected to greatly influence competitive bidding systems. In March 1988, Boston Edison filed its second Request for Proposals with the Massachusetts Department of Public Utilities, soliciting 200 MW of capacity and associated energy from Qualifying Facilities to be in service by 1994. Orange and Rockland Utilities (ORU) and Niagara Mohawk (NMPC) filed competitive bidding guidelines and RFPs in October 1988 in unbounded scores (BECo, 1986). The price score was determined by the ratio of avoided cost divided by the bid price. In the hypothetical case where the bid price approaches zero, the score could approach infinity. In contrast, for most of the bidding systems shown in Table 3-1, the price score is computed by benchmarking the bidders price against some ceiling price that is an estimate of the utility's avoided cost in the absence of the auction. For example, in its second RFP, BECo computes the price score as a percentage of avoided cost, which eliminates the unboundedness. The four bid evaluation systems are also linear in the sense that the score for each category is additive, yielding a total project score. In contrast, a system proposed by Western Massachusetts Electric Company (1988) has non-linear interactions, although we defer discussion of this approach because it is atypical.

It is also very important to recognize the difference between the nominal weight of a particular factor and its real weight, which can only be determined based on the actual distribution of bids in an auction. For example, assume two non-price factors are assigned equal weights in a scoring system (e.g., each factor is worth 5% of the total points). The bids for one factor are tightly clustered with little variation, while scores for the other attribute vary widely. In this example, if these were the only two factors, the outcome would be determined by the factor with scattered bids. That is, the real weight is determined by the actual distribution of bids and cannot be known without such information. Our discussion refers only to the nominal weights for each factor, because it is impossible to determine the real weights since, at this time, we only have information on the form of an evaluation scheme. We use this simpler approach because of data limitations, although we examine the issue of nominal versus real weights in Chapter 6 when we compare the scores for a group of generic bids.

Non-Price Factors

The existence of non-price factors is one of the main reasons that electric power auctions are not amenable to simple oral auctions. In fact, the bulk of the detail in "open" systems is often devoted to factors that differentiate the kind of project being proposed, its likelihood of success, and the financial terms under which the bidder proposes to be paid. We now discuss these factors in more detail.

Supplier Assurance

The features grouped in the "Supplier Assurance" category address both the near term prospects for the successful development of a particular project (i.e., ''development'') as well as its long-term viability (i.e., ''longevity''). In one sense, the buyer wants to be protected from accepting deals that are "too good to be true." If a bidder offers an unusually attractive price, it may be due either to remarkable efficiency or unrealistic optimism. In the latter case, the utility may end up with worthless promises for a project that has little chance of materializing. It is, of course, difficult to obtain guarantees from suppliers that are truly valid indicators of realistic, achievable projects. Therefore, many of the indicators used to assess the development viability of a bid are minimum threshold criteria. Other factors are indicators of likely success or represent very mature stages of project development. The factors examined include: site control, project engineering, financing and permitting, and the experience of the developers (which are shown under the term "Development" in Table 3-1). For example, among these factors, site control, project engineering, and fuel contracts reflect minimal necessary requirements that any serious bidder ought to be able to meet. These are necessary conditions that do not provide positive information on the ability to develop. Without meeting these conditions, a project is not a serious contender. In contrast, factors such as environmental permits and firm financing arrangements are almost too stringent to be reliable indicators. Most projects cannot be expected to meet these requirements at the time of a bid. Ideally, project viability factors should be indicators of the probability of obtaining permits and financing. Additional work in this area would be useful in order to develop indicators that help discriminate on the chances of developing and operating successful projects.

''Longevity'' is an explicit category only in the BECo and NMPC systems and addresses factors that would indicate long-term performance viability for the supplier. For example, assurance of long-term fuel supplies means that the project will be able to operate physically. Projections of reasonable debt coverage means that excess leverage should not cause a default on delivery. Other factors include long-term maintenance contracts and operating security deposits. ORU places somewhat less emphasis on longevity, as its bidding system awards points only for security of fuel supply.

Fuel Choice and Flexibility

''Fuel Choice and Flexibility'' factors refer to the buyer's concerns with diversity of fuel mix. The underlying issue is the risk of dependence on fuels that may come into short supply, principally oil and gas. The Virginia Power system is the most explicit on this point, and arguably places the largest value on this factor. Their RFP makes a particular point about emphasizing the value placed on coal-fired projects, especially those using coal produced in Virginia.

1988b). BECo also identified this problem in their most recent integrated resource plan (Boston Edison, 1988b).

Other factors categorized under the heading of System Optimization include favorable location in the transmission grid, diversity of ownership among the set of suppliers, and unit size. By design, VP is the least transparent on these questions. They allocate 10% of the evaluation weight to such concerns in addition to the virtual requirement of dispatchability. BECo gives the least weight to system optimization.

Front Loading

The category called "Front Loading" addresses the timing of payments requested by bidders. Utilities typically project that the value of power will increase significantly over time in their estimates of long-run avoided costs. Generally, this occurs because of the rather low level of oil and gas costs relative to future expectations or because a utility has short-term excess capacity. Under these circumstances, bidders may need payments that exceed estimated avoided costs during the initial years of a project; these payments are "front loaded." Capital-intensive technologies are more likely to have financing constraints that require front-loaded payments (Kahn, 1988; see chapter 6). For such a payment stream to have value to the buyer, it must be substantially lower than avoided cost in the long run. Buyers perceive a risk from these arrangements even when the discounted cost of a front-loaded bid is less than the discounted avoided cost. The risk is essentially that the supplier will default before the buyer has been "paid back" for the excess payment in the early years of the contract.

The four utilities have taken very different positions towards "front-loading." Virginia Power is unique and quite accommodating toward the front-loading needs of bidders, while Boston Edison is hostile. VP requires that bidders unbundle their offer into a capacity and an energy price. VP's requirement of dispatchability means that there is no guarantee on the amount of production from any project. This creates a strong incentive to bid one's cost on the energy price, because inclusion of a profit term in the energy price would produce profit results that are unpredictable. VP does indicate that the preferred form of the capacity bid would be a 15-year level stream such that no more than 90% of the total present value was in that period and no less than 10% in the last ten years. This allows for front loading of the capacity bid relative to some hypothetical escalating stream, such as the widely used economic carrying charge approach advocated by NERA for marginal cost analysis (NERA, 1977). The economic carrying charge method "back-loads" capacity charges by structuring them to escalate at the assumed rate of inflation. The Texas Utilities Electric Company Avoided Cost Offer is a prominent example of the NERA approach applied to pricing cogeneration capacity payments (Texas Utilities, 1985).

In contrast, Boston Edison places substantial burdens on bidders that seek front-loading. Their 20% weighting consists of two elements. First, there is a measurement scheme to determine how long the ratepayer will be "exposed" to overpayments. The mechanism is similar to the Payment Tracking Accounts used in some PURPA contracts where front-loading is a feature (Kahn, 1988; see Chapter 6). Balanced against this measure of the length of exposure is a system which rewards bidders that post security for the amount of ratepayer exposure. The underlying concern addressed by these methods is that front loading is a form of loan provided to the included; while the difficult requirements such as permanent financing and environmental permits would be excluded. The system proposed by the CPUC does not address all the categories identified in Table 3-1 (e.g., fuel choice or maximum bid size).

Dispatchability is treated in a rather unique fashion. The CPUC draws a distinction between the theory of avoided cost underlying the entire resource planning procedure and the subsequent optimization of the power system. The avoided cost is defined in terms of a hypothetical new facility called the "Identifiable Deferrable Resource" (IDR). The process of determining the IDR is spelled out in some detail (CPUC, 1986). Winning bidders receive prices that are some fraction of the IDR costs for the period of time the IDR would have operated. Any other production by the bidder is paid using short-run methods that are updated as system conditions change (CPUC, 1987). If the producer were to curtail output as a means of improving overall system efficiency, they would be paid for this under a special "performance adder" arrangement. The dispatchability adder would then capture the additional value of this feature beyond what was embodied in the IDR (CPUC, 1988).

Front loading is strictly forbidden under the proposed CPUC system. All capacity and certain energy payments would be strictly escalating according to a pre-specified escalation rate. This is a rigorous application of the economic carrying charge method. Power contracts would be limited to 15 years.

Although the proposed CPUC procedure has gone through a long process of development and definition, it has recently come under substantial criticism from the principal California utilities. The utilities are particularly concerned about the second-price mechanism for paying auction winners and the inflexibilities associated with relying excessively on constraints rather than weights (Pacific Gas and Electric, 1988). In fact, the two issues are linked. A second price auction is thought to have efficiency properties that are superior to the more traditional first price or discriminative auction procedure. The differences between these procedures are reviewed with particular reference to electric power in the recent literature (Rothkopf, et al, 1987). However, in practice, the second price procedure is only practical where the commodity being sold is sufficiently simple and homogeneous so that non-price features are irrelevant to the acquisition process. This condition is not met in electric power. As our brief discussion of dispatchability indicates, it is difficult to accommodate different project characteristics in a system of constraints. It is unclear whether the CPUC will revise its previous decisions on auction format to accommodate the concerns of the utilities, or continue along the path that it has been developing.

3.4 Consolidated Edison's Proposed Integrated Supply and Demand Auction

Consolidated Edison's proposed bidding system is interesting because they have a unique approach to determining system effects in their economic evaluation method and because they do not assign an explicit weighting to non-price factors in the initial stages of bid evaluation (Con Ed, 1988). Instead, Con Ed proposes a normalization procedure that monetizes the non-price features of a particular bid by comparing it to a reference bid. Their basic idea is that the absolute value of non-price factors can only be determined relative to the features offered by a particular alternative resource. This is a slightly more flexible version of the CPUC's concept of an Identified Deferrable Resource. However, in Con Ed's proposal, the reference or baseline bid is not an administratively determined avoidable resource, but the least cost bid absent non-price conclude our examination of bid evaluation systems with a brief discussion of features that tend to work against capital-intensive technologies as well as the ostensible rationales for these design choices.

We have previously identified front loading, explicit fuel preferences, and contract length as features that may critically affect the prospects for capital-intensive technologies. Systems such as BECo's, which strongly penalize front loading, will end up encouraging fuel-intensive projects. In contrast, ORU adjusts its measure of front loading impact by factors that explicitly benefit certain capital-intensive technologies. Bid prices for solid fuel projects are allowed to be greater than the utility's avoided costs in the initial years of the project by 35%, while oil- and gas-fired projects are limited to 20%.

The rationale for specifying contact length periods relates to perceptions of risk. The proposed California system is designed to limit ratepayer exposure to long term contracts by fixing a maximum length of fifteen years. The cost of this approach is an implicit commitment to oil and gas fuel price uncertainty. Ironically, because indexing provisions are typically used in setting the avoided energy payments, in most cases, ratepayers would bear the risks associated with uncertainties in oil/gas price. Thus, while the California system is consistent in its bias toward liquid fuels, the choice is not made explicitly as a policy statement, but only as the residual of nominal concerns about contract rigidities and the minimal financing needs of fuel intensive suppliers.

Finally, we note that some capital-intensive technologies are more attractive if economies of scale can be captured. However, several auction design features can affect the size of individual projects. We have already discussed possible constraints imposed by utilities that limit the size of individual projects. For example, BECo limits the bidders to projects that are no more than 25% of the total quantity to be purchased. In this solicitation the total quantity being sought is 400 MW, so the maximum individual bid would be 100 MW. This is not large enough to capture all potential scale economies.

Even where there is no explicit limit on individual bids, if the utility's resource need is small, then the effect would be the same. For example, Orange and Rockland is a relatively small utility which needs only 100 MW of additional capacity. In these situations, it would be socially beneficial for some market aggregation mechanism to operate so that scale economies can be realized. One possible alternative would be to organize power purchase and evaluation decisions at the level of individual states. Regulatory control would still be operative at the state level, but scale economies could be realized and the benefits allocated to small utilities on the basis of joint participation. At least one state PUC (e.g., Vermont) is considering a scheme of this kind.

A final consideration where scale economies are concerned is the viability of linear scoring systems. The implicit assumption of the linear approach is that project economics do not interact with one another or with the underlying system. Once scale economies begin to be realized these assumptions may no longer be valid. At that point, other evaluation methods may be needed. We will discuss this issue of non-linear effects in more detail in Chapter 5 when we analyze large-scale procurements, such as that conducted by Virginia Power.

4. THEORETICAL ASPECTS OF BID EVALUATION: MEASURING AND PRICING RISKS

4.1 Overview

In Chapter 3, we surveyed various approaches used by utilities to evaluate price and non-price factors. Design choices are often motivated by the perception of risk and uncertainty on the part of the utility (and/or regulator). In addition, private power producers potentially face greater risks than the utility, because the seller may be much less diversified. The seller's costs, some of which are highly uncertain, must be covered by a revenue stream sufficient to attract capital. The consequences of miscalculation are project failure. Although project failures also impact the utility, the utility's risk is likely to be spread over many projects. Therefore, the design of contract terms must balance the risk-sharing function between buyer and seller with incentives that encourage private developers to perform efficiently.

In this chapter we examine the approach adopted by several utilities to measuring and pricing risks in their bid evaluation systems. It is not possible to treat this subject exhaustively because in many cases an adequate conceptual framework does not exist. Moreover, in some cases, data to estimate the magnitude or price of risk are weak. Our treatment is exploratory and focuses on two areas that impact capital-intensive technologies: front-loading and fuel diversity. We present an economic framework to evaluate front-loaded bids and use it to illustrate the undue burden implicit in the BECo bid evaluation system. This model is flexible enough to be incorporated into most scoring systems. In Chapter 2, we described briefly how utility concerns about fuel diversity can benefit capital-intensive technologies.[1] This argument is generally accepted, although there is considerable conceptual ambiguity regarding who accrues the value of fuel diversity. We examine the range of potential answers to this question, and make estimates in some of these cases.

In addition, we briefly discuss approaches to evaluating the environmental impacts of generating resources and review the treatment of risk in project viability (i.e., the supplier assurance category in Chapter 3) and a related issue, the costs of mitigating project failure. Project viability, the danger that bidders who are awarded contracts will not actually deliver as promised, is a major risk for the utility. We review the value and cost dimensions of several insurance mechanisms that reduce or eliminate the costs of failed or abandoned projects. Our analysis suggests that measurement of project viability and project failure insurance mechanisms are areas in which additional research is needed.

4.2 Front Loading of Payments

Figure 4-1 illustrates the fundamental issue involved in front-loading in a simple schematic fashion. The utility's expected avoided cost trajectory, which escalates over time, is shown along with a fixed price bid, which is constant over the lifetime of the project. Note that the present value (PV) of the utility's avoided cost is greater than the fixed price bid. Therefore, the

[1] See Section 4 in Chapter 2.

bid is preferable to avoided cost, all other things being equal. However, the bid price exceeds avoided cost in the initial years of the project, which reflects the seller's preferred payment stream. The seller's payment stream creates an exposure to the risk of project abandonment, which is shown by the hatched area. At some later point in time, as avoided costs increase, the present value benefits of the low bid price equal the present value exposure and the economic risk is eliminated.

Some utilities and regulators view front-loaded bids as undesirable because they believe that they are in effect subsidizing the project in its initial years by providing loan financing to the developer. Our method of evaluating front-loaded bids is based on a formalization of this intuition.

4.2.1 Front-Loading as a Loan

We want to model the economic relationships involved in front-loading to yield a systematic procedure for evaluating such bids. We rely on the intuition that front-loading is like a loan, but formalize this notion in a consistent fashion (see Appendix A for a more in-depth discussion of the implicit loan method).

We begin qualitatively by considering two bids that have the same present value as the utility's avoided cost. The only difference between the bids is that one is front-loaded. The first bid is equal at every point to the utility's avoided cost stream, which we call a neutral bid. The second bid is front-loaded and we believe intuitively that it is worse from the standpoint of risks to ratepayers than the neutral bid. We then separate the front-loaded bid into two components: Part A, which is equal to the first bid at every point, and Part B, which is just the difference between the first bid and the front-loaded bid. Part B has a negative cash flow in the early years, which is then followed by a positive cash flow. The positive cash flows in later years are greater in absolute value than the negative cash flows initially, so that they are equal in terms of discounted present value. The basic pattern of negative cash flow followed by compensating positive cash flow looks like the pattern of a loan.

We want to account for the intuition that front loading is worse than neutral streams. One way this can be represented is to assume that the present value of Part B is actually negative rather than zero. To achieve such a numerical result (i.e., negative PV), the discount rate for Part B must be higher than normal. The rationale for introducing a higher than normal discount rate is to account for the risk that some of these loans will not be repaid. Lenders normally apply a risk premium to compensate for the probability of loan default. In our context this means that front loaded bidders may not supply power at the end of their proposed contract, which we interpret as a default on the implicit loan.

Conceptually, then we can describe the appropriate technique for evaluating front-loaded bids as a process of separation into a neutral and a loan component. The neutral part will be treated like any other bid (i.e., it will be evaluated at the utility's normal discount rate). The loan part will be discounted using a risk premium over and above the utility's normal discount rate. To formalize this concept, we must specify the meaning of neutrality, which will then allow us to define how to separate a bid into components.

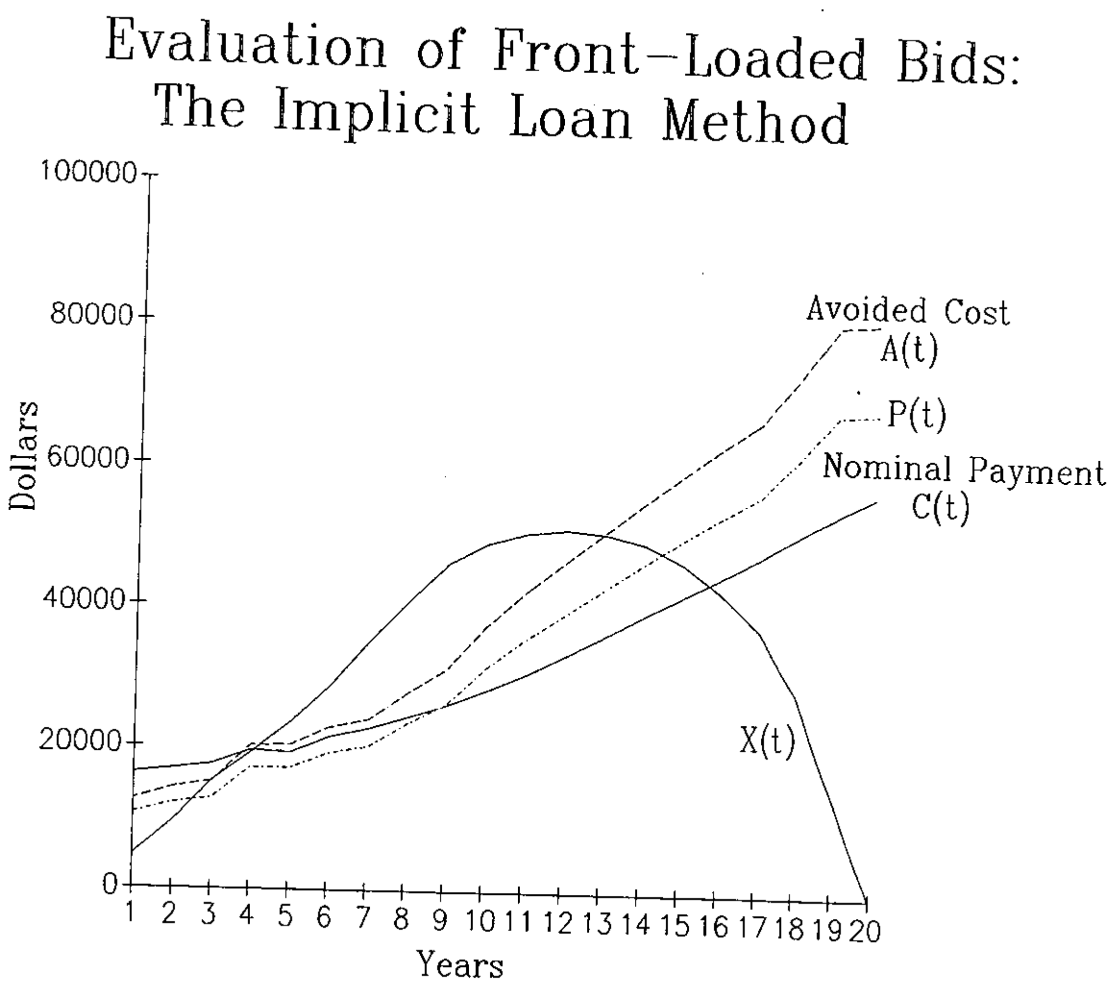

Figure 4-2 illustrates our approach to evaluating a front-loaded bid, called the Implicit Loan Method. Nominal payments, C(t), to bidders exceed the utility's avoided cost, A(t), in the first four years of the project. P(t) represents the "neutral" payments, which are proportional to the utility's avoided cost. X(t), represents the cumulative loan overpayment, which must be repaid by the end of the contract term.

BECo's system, the number of years until liquidation of the accumulated over-payment, called the break-even score (column 8), is the key indicator of front-loading. The break-even score is effectively a measure of the length of the front-loading loan. Other loan parameters of possible interest, such as the magnitude of the exposure or its risk, are ignored by BECo.

Table 4-2. BECo's scoring of front-loaded bids: Calculating the breakeven score.

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Year	Nominal Payments C(T)	Nominal Avoided Cost A(T)	PV factor at 10.88%	PV of Payments	PV of Avoided Cost	Over Payment	Cumulative Over Payment with Interest 10.88%	Break Even Score
1990	16144	12510	1.000	16144	12510	3634	3634	0
1991	16864	14244	0.902	15209	12846	2620	6649	0
1992	17590	15111	0.813	14307	12291	2479	9852	0
1993	19533	20240	0.734	14329	14847	-707	10217	0
1994	19261	20325	0.662	12743	13447	-1064	10264	0
1995	21496	22841	0.597	12826	13629	-1345	10036	0
1996	22744	23992	0.538	12239	12911	-1248	9880	0
1997	24345	27829	0.485	11815	13506	-3484	7471	0
1998	26154	31298	0.438	11448	13699	-5144	3140	0
1999	28361	37529	0.395	11195	14815	-9168	-5687	1
2000	30759	42422	0.356	10951	15103	-11663	-17968	2
2001	33405	46707	0.321	10726	14997	-13302	-33225	3
2002	36260	50992	0.290	10500	14766	-14732	-51572	4
2003	39270	55290	0.261	10256	14440	-16020	-73203	5
2004	42058	59475	0.236	9906	14008	-17417	-98585	6
2005	44867	63463	0.212	9531	13481	-18596	-127907	7
2006	47767	67017	0.192	9151	12839	-19250	-161073	8
2007	50883	73521	0.173	8792	12703	-22638	-201236	9
2008	53830	80705	0.156	8388	12576	-26875	-250005	10
2009	56791	81035	0.141	7981	11388	-24244	-301450	11
			SUM	228437 SPVB	270801 SPVC			11 B.E.YRS

Table 4-2 is a facsimile of BECo Evaluation Sheet #5 for a hypothetical project with a front-loaded bid (Project A).[3] This project would receive 15.6 price points because the ratio of the sum of present-value payments to the bidder (Sum PVB) to the sum of present-value avoided costs (Sum PVC) is 0.843. The bidder computes the score for front-loading by determining the number of years in which the cumulative overpayment with interest is negative. In this example, the front-load loan has been repaid by year 9. The bidder subtracts this number of years from the maximum number of years allowed for a long-term contract (20 years) to give 11 years. The

[3] The bid data were taken from an example included in the Western Massachusetts Electric Company RFP. Note that the avoided costs are a somewhat smoothed version of the BECo estimate.

calculation for a situation in which Project A decides not to post any financial security, and thus receives 0 points in this category (see Table 4-4).

Table 4-4. BECo's scoring of a front-loaded bid without additional security.

Project A		Points
Price Factor points	=	15.6
Breakeven Score	=	16.5
Front Load Security	=	0.0
Sum	=	32.1

Project A* (without front-loading)		Points
Equivalent Price Factor	=	-17.9
Breakeven Score	=	30.0
Front Load Security	=	20.0
Sum	=	32.1

SPVB/SPVC = b = 1.179

===> R = 67.4%

Project A now receives a total score of only 32.1 points in these three categories. However, Project A*, the equivalent bid, is still awarded a total of 50 points in the breakeven score and financial security categories, because it is not front-loaded by our definition. To reconcile the two characterizations, the equivalent bid must receive a negative price factor score! We perform the computation to illustrate the absurdity of the situation. In this case, Project A* must receive -17.9 price factor points in order to have an identical total score (32.1 points), which would correspond to b = 1.179. Project A*'s bid is then 18% above avoided cost, which violates the threshold constraint imposed by BECo that bids can not exceed the utility's avoided cost. The implicit risk-adjusted interest rate would be 67.4%.

The results for Project A under BECo's proposed system are driven largely by the relatively high weights given to the breakeven score and front-load security factors relative to price. For comparison, we repeat the calculation using Niagara Mohawk's (NMPC) proposed bid evaluation system. NMPC's approach is identical to BECO's system with one significant difference. NMPC gives a much higher relative weight to the price score compared to the economic risk factors. The maximum points awarded for price, the breakeven score, and front-load security in NMPC's system are 850, 50, and 25 points respectively. Table 4-5 summarizes results for Project A under NMPC's bid evaluation system for the two extreme cases: the bidder posts full financial security and situations in which no additional financial security is offered.

rate. Clearly, such a relationship should account for the degree of exposure incurred by the buyer, some measure of the maturity of the loan, and the credit-worthiness of the borrower. These are standard problems in project finance and the front-loading problem does not alter them in any fundamental way. Incorporation of these additional risk factors into the IL model is another useful research topic that could improve existing bid evaluation systems.

4.3 Fuel Diversity

Capital-intensive technologies are substitutes for oil and gas consumption. The value of this substitution depends upon the level of oil and gas prices, which are quite uncertain in the long run and unpredictable. One way to think about the value of fuel diversity is in terms of insurance. Over the long-term, electric bills are a gamble. They depend on uncertain future oil and gas prices to the degree that the utility depends on these fuels. Choosing solid fuel or renewable energy technologies will reduce the variability of future electricity revenue requirements. Our willingness to pay a premium for this reduction in variability reflects the insurance value of fuel diversity.

It is useful to inquire where this risk premium comes from and how it relates to ordinary economic evaluation criteria. Let us assume that we have an economic agent who is aware that there is a roughly equal chance that either ''good'' or ''bad'' outcomes of similar magnitudes could occur with respect to future energy costs. We assert that "bad" outcomes are relatively worse for many economic agents compared to the beneficial effects of "good" outcomes. This view is illustrated in Figure 4-3, which plots total utility energy costs against an abstract measure of value, called "points," which would represent the utility function of the agent to an economist.

We represent the uncertainty in this situation using a simple, two-point probability distribution. There is a 50% chance that total utility energy costs will be $110 billion, and a 50% chance that these costs will only be $90 billion. The expected value is $100 billion, which is the value that would be used if risk preferences were not considered. However, Fig. 4-3 shows that the expected utility of this economic agent corresponds to a cost higher than the expected value. This means that if all uncertainty could be eliminated, and the economic agent could obtain the average utility of the high and low cost outcomes (in this example 98 "points"), then the agent would pay $103 billion rather than $100 billion. The difference between the certain equivalent cost and the expected value is called the risk premium. It arises because the utility function of the economic agent is curved; falling faster in the high cost case than it rises in the low cost case. This example represents a "risk averse" actor; the degree of risk aversion is represented by the curvature of the utility function.

We estimate the value of fuel diversity by applying the conceptual framework shown in Fig. 4-3 to the particular situation of the electric utility power purchase decision. The most difficult problem that must be confronted is identifying whose utility function we are trying to estimate. There are many economic agents involved in the electric utility power purchase decision. We must be clear regarding to whom we imagine the value of fuel diversity accrues in order to use the risk premium notion. We examine the various approaches that can be taken to this question and estimate the value of fuel diversity for one of these decision-makers: the average electricity consumer.

4.3.1 Risk to Whom?

Many economic agents are effected by the power purchase decision. The most direct impacts are on ratepayers, and they, in some sense, represent the principal perspective from which risk evaluation ought to be conducted. Even within the broad category of ratepayers, there are important distinctions. It is well known that risk aversion (i.e., the curvature of the utility function) differs by economic status. The poor are commonly perceived to be more risk averse than the wealthy. The intuition behind this observation is that high cost outcomes curtail the consumption of basic necessities for the poor, whereas they may only impact discretionary spending among median or upper income groups. Another important distinction among ratepayers involves the potential bypass customer. This is usually a large industrial electricity user with the potential to cogenerate and leave the utility system if rates become too high. The role of bypass actually highlights the stake of other economic agents, namely managers and shareholders.

Both managers and shareholders are affected by fuel price risk, but in ways that differ significantly from the typical ratepayer. For the typical ratepayer, fuel price risk impacts their consumption behavior. If electricity bills are higher, then there is less money available for purchasing other goods and services. The problem of high utility rates is quite different for managers. In the extreme case, the manager could lose his job if utility rates are too high and many large customers decide to leave the system. Even in anticipation of such outcomes, the utility may reduce employment levels as a means of lowering costs and retaining customers. This situation has a potentially larger impact on managers than any form of price risk may have on consumers, because the manager is not diversified compared to the consumer. Electricity is only one good purchased by the consumer; thus price risk in this dimension only impacts welfare through that fraction of the budget spent on electricity. It is unusual for this fraction to exceed 10% for residential households, while, on average, electricity accounts for less than 5% of a household's total budget. On the other hand, utility managers have only one job and job loss is an extremely bad outcome.

In principle, utility shareholders are affected more directly than managers by price increases that induce large scale bypass because their earnings could be reduced. The role of the regulator is critical in such a scenario. First, we assume that fuel prices rise due to exogenous circumstances. The utility then raises rates to recover costs, which may induce some industrial customers to bypass the utility's system. To maintain the same level of earnings as before bypass, the utility must raise rates to remaining customers. The regulator delays this process or refuses to make the entire adjustment, therefore earnings fall. If the regulator had raised rates completely, it may have induced further bypass.

In this hypothetical scenario, the welfare of utility shareholders is reduced if energy cost increases result in reduced earnings. To the degree that shareholders are diversified, the magnitude of this effect is reduced. Any estimate of the risk premium of shareholders must include at least three components. First, if the principal effect lies through bypass, some model of the bypasser's elasticity with respect to price is needed. Second, shareholder returns only go down because the regulator will not promptly restore earnings lost through bypass to their previous level. Thus, some model of regulatory policy is required. Finally, to capture the diversification of shareholders, some account must be taken of the capital market response to utility-specific estimate. To estimate Eq.(4) we must know how uncertain the distributions of household income and electricity price are as well as the correlation of these variables.

It is useful to describe the interaction of the terms in Equation (4) qualitatively before proceeding to estimate their individual components. It is generally assumed that electricity price and household income are negatively correlated. All other things being equal, an increase in the price of electricity will be associated with a decrease in household income, and vice versa. In this case, we are referring to macroeconomic effects. If electricity costs increase, productivity is adversely affected, which ultimately reduces income available for households. Conversely, when electricity costs go down, productivity increases and household income goes up. Note that the negative sign of this correlation cancels the negative sign that is contained in the entire equation. This indicates that there is a positive consumer benefit to stabilizing the price of electricity. The magnitude of the benefit depends on 1) the variability of income (i.e., CV(Y_h)), 2) variability in the price of electricity (i.e., CV(P)), and 3) on the degree of risk aversion (i.e., R). If the two CV's are small, then the value of certainty must be less; and conversely.

To apply Eq.(4) to our problem, we transform and present the price and income variables in terms that are more appropriate for our context and can readily be estimated. We express the price of electricity as the sum of a fixed and a variable component. The variable component is primarily fuel. Purchased power substitutes primarily for fuel. The value of reducing fuel price uncertainty will depend on how much of the electricity bill is due to fuel costs. We also need to develop a relationship between household income and fuel prices, which is used to estimate the value of the correlation coefficient (see Appendix B for details of these calculations and full derivation of the equations).

We draw on several available data sources in order to derive our estimates. We use a recent DRI forecast of future natural gas prices, which includes high, medium, and low price trajectories over twenty years. DRI assigns a 20% probability to the high and low case, and a 60% probability to the medium case. We can derive a CV of prices from this forecast. The natural gas price forecast shows a CV in real terms that ranges from a maximum of 40% to a minimum of 23% (see Appendix B, Table B-2). The CV of electricity prices is some fraction of these estimates, reflecting the fuel mix of our hypothetical electric utility. Since the utilities for which fuel diversity is likely to be valuable are heavily dependent on oil and gas, that fraction should be relatively high. We assume that 60% is a a reasonable upper bound.

A second key estimate is the linkage between income and fuel prices. We draw upon studies that were conducted in the context of determining the optimal size and value of the U.S. Strategic Petroleum Reserve. The value of stockpiling oil depends fundamentally on the amount of economic damage that fuel price increases can inflict upon the economy. Storage is the basic form of insurance for price stability in commodity markets, so the framework involved in analyzing that problem is closely analogous with the fuel diversity problem in which we are interested. We rely on empirical estimates based on a recent study by Huntington (1986), in which he found that a \$1/barrel increase in the cost of oil results in a \$4 billion loss in real purchasing power.

Finally, we must select an appropriate value for the relative risk aversion parameter (R). We can think in terms of some average ratepayer whose risk preferences reflect the population at

Fuel choices raise other issues (e.g., national security, environmental concerns) that can potentially influence the design of a bid evaluation. These issues are usually external to the jurisdiction and/or economy that is affected by utility resource planning. Nonetheless, because issues of this kind are raised by policy-makers who must approve bidding systems, we will discuss two key externalities associated with fuel choice: the economic benefits of reduced oil consumption and incorporation of environmental impacts in bidding systems.

4.4 Fuel Choice Externalities

The standard definition of an economic externality is any aspect of a transaction whose costs or benefits do not accrue to the parties directly involved. The political system periodically adjusts the requirements imposed on transactors that may change a given effect from being external to being internal or vice versa. Such choices are also posed in the design of bidding systems. State regulatory authorities may wish to embody policy preferences in the evaluation scheme that reflect a social value which is external to the economic interests of the transactors. The effect of such a policy choice is to improve the competitive position of technologies offering the desirable attribute, and perhaps to raise the cost of power to consumers. In this section we examine two kinds of externalities associated with fuel choice: the economic benefits to the U.S. from reduced oil consumption and environmental concerns. Sample calculations show that the size of such effects can be large.

4.4.1 National Benefits of Reduced Oil and Gas Consumption

Our discussion of the value of fuel diversity addressed the willingness of various economic agents to pay for reduced fuel price risk. The risk in question was the chance that oil and gas prices would be very high. To insure against this risk, there is some willingness to pay a premium for other fuels above their expected value. Apart from these risk considerations, there are other benefits to reduced oil and gas consumption. Because oil and gas are non-renewable resources, reducing the use of these fuels can have the benefit of reducing their long-run price. This benefit is external in the sense that it flows to all consumers, and not simply to those responsible for reduced oil and gas use. In this section we provide some very rough estimates of the possible economic benefits of reduced oil consumption to the nation.

We assume that a utility that purchases power from a producer that uses an alternative fuel (e.g., coal, hydro, biomass) effectively displaces some fraction of the potential oil and gas demand of the utility sector. Currently, oil- and gas-fired generating units are the marginal resources for most U.S. utilities. Gas is the dominant fuel, although much of the fossil-fueled U.S. generating capacity has the capacity to switch fuels (EIA, 1985).

In our analysis, we initially make the assumption that oil and gas are close substitutes over the longer term, which allows us to treat the complex links between world oil and gas markets in a quite simplified fashion. Over the long-term, we assume that using coal as an alternative fuel reduces the world demand for oil. This view is not realistic as these markets are functioning today. Currently, the linkage of oil and gas markets is weak because of substantial availability of gas supplies at low costs, i.e., gas use can increase and its costs rise without being affected by oil prices. Over the longer term, the ability of freed up gas to displace imported oil depends on one's view of the gas markets. If the weak linkage continues over the long run, this implies that half as large (assuming a lower value of 0.5 for η_s), it could still be a factor in determining the outcome of the auction. Our analysis of short-term effects, while illustrative for showing the computational procedures, has some obvious limitations because it does not capture feedbacks between oil demand and price and because the elasticity assumptions are just guesses. Thus, we now examine the potential national benefits of reduced oil consumption over the long-term, which allows us to develop an improved estimate of the elasticity of price with respect to demand.

Over the long-term, it is important to recognize that one-time changes in demand will impact current as well as future prices of oil. DOE's Oil Modeling System provides a conceptual approach that allows us to estimate this effect, which relies on one popular view of long-run oil price formation (System Services, 1985). Over time, oil resources will be depleted. At some time in the future (T), oil will become more scarce and expensive, and ultimately the price of oil will reach that of a backstop fuel. The standard economic model of the price path over time says that the oil price should rise at the real rate of interest (Hotelling, 1931).[6] If we know the rate of increase in oil prices, it is then possible to work backwards from time T and the backstop price at that date to find oil prices for periods prior to the exhaustion date.

[6] This is essentially a consequence of the fact that at any other rate of increase OPEC could make money by selling the oil either sooner or later.

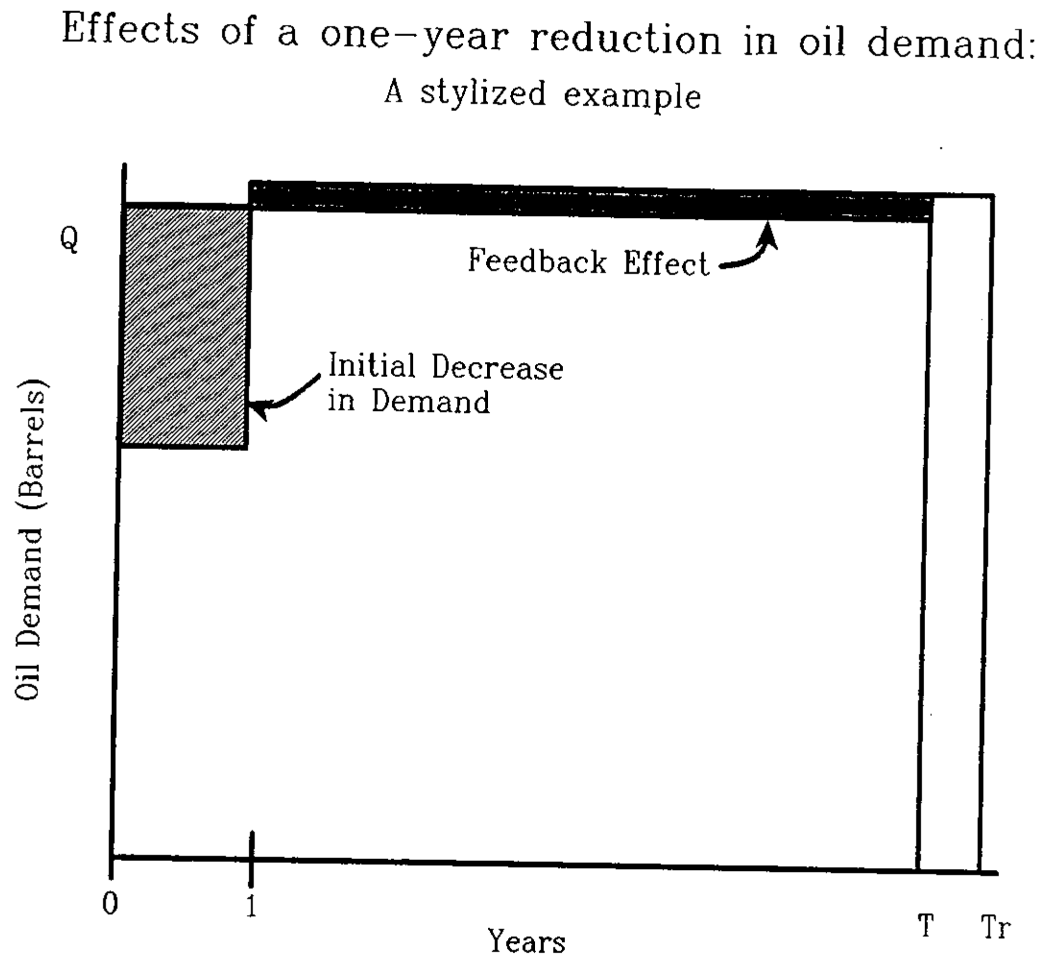

Figure 4-5. A stylized example of the effects of a one-year reduction in oil demand.

Figure 4-5 shows the initial decrease in oil demand as a result of the choice to use an alternative fuel, the subsequent increase in demand (in response to reduced prices), and the net result, which is to move the exhaustion date into the future. Our analysis suggests that the magnitude of the subsequent increase in oil demand is less than the initial decrease (see Appendix C for details), which leads to the results given by equation (8).

$$S = \frac{m^* \cdot \eta \cdot P_o}{b} \tag{8}$$

The form of the equation is similar to our analysis of short-run effects, however note that several of the parameters need to be interpreted somewhat differently. The parameter m^* is the ratio of the cumulative total of all future U.S. imports to the current year's world oil production, which is obviously much larger than m. We develop a very rough estimate of U.S. imports for an 80-year time period. The parameter η is the elasticity of all future oil prices with respect to the current of technologies. In addition, the relative competitive position of projects may change because the level of acceptable emissions changes over time, and thus environmental costs are not stable. As new facilities are constructed in areas subject to environmental constraint, siting authorities have increasingly relied on the "offset" concept to maintain compliance with required levels. New facilities must be substantially cleaner than existing facilities. Production from the new facility displaces production from older plants and the net emissions stay the same or decrease. The reduction in emissions from old facilities offsets the increment from new facilities.

The logic of environmental offsets is particularly important in areas, such as Los Angeles, with severe air quality problems. The South Coast Air Quality Management District (SCAQMD) oversees this process for the Los Angeles air basin. In addition to its standard setting role, SCAQMD also mandates the engineering approach that will be used to meet requirements under its Best Available Control Technology (BACT) authority. Recent estimates of the BACT costs for controlling nitrogen oxide (NOx) emissions, have been used to argue for environmental credits in resource planning (Independent Energy Producers, 1988). This argument has also been extended to California's competitive bidding context as well, because explicit resource planning underlies the bidding process. Proponents of environmental credits argue that a bidder whose project would result in a reduction of NOx emissions in the South Coast Air Basin ought to get the monetary equivalent of the BACT cost to achieve that same effect. Proponents estimate the magnitude of the credit to be approximately 1 ¢/kWh. The relative importance of environmental benefits has also been discussed and debated in New York (NYSEO, 1989; Reeder, 1989). For example, in reviewing Orange & Rockland Utilities proposed bid system, the New York Public Service Commission decided that environmental factors should be worth about 15 points (out of 100) relative to price and other non-price factors (NYPSC, 1989).

One of the major issues raised by the environmental credit approach is the question of whether or when the particular reductions in emissions will be mandated. For example, the NOx reduction credit calculated for the LA Air Basin is based on a putative calculation. It is an estimate of what it would cost to reduce NOx emissions if SCAQMD ordered this to be done. SCAQMD is considering rules that require reductions in NOx emissions, but has not issued an order. Thus, the credit is not an avoidable cost in the PURPA sense (i.e., internal to the utility system), but an external cost in the standard sense in economics.

Even if we assume that that SCAQMD was definitely going to impose NOx restrictions, we would still need to address uncertainties in pollution control equipment. In reality, BACT is a moving target because pollution control technology improves over time. Moreover, alternative strategies may offer lower or higher cost options for particular emission reduction goals. The environmental credit concept does not incorporate competitive effects in pollution control strategies and provides few incentives for lower cost methods of achieving environmental goals.

At present, there has been very little discussion of how to incorporate environmental goals into competitive bidding through means other than the environmental credits approach. As concern about these issues increases, it can be expected that this deficiency will become more apparent.

One consultant that attempts to track project development in Northern California has identified three key factors that affect project viability: (1) developer experience, (2) expansion of existing facilities, and (3) complexity of environmental permitting (Morse, Richard, and Weisenmiller, 1989). The intuition underlying the choice of these factors is clear. Private producers that have succeeded previously have an important advantage, because development is a difficult and complex process. This advantage is particularly marked in cases where the developer is simply expanding output at an existing facility, rather than proposing a project on a new, undeveloped site. In general, it is much less difficult to obtain environmental permits for expansion of existing facilities compared to obtaining permits for a new development. The complexity of permitting is also influenced by choice of technology. For example, it is typically easier to site projects with fewer emissions. In addition, there may be fewer constraints in siting projects with more remote locations, although sites near scenic or wilderness areas may incur significant environmental and permitting problems. In practice, it may be difficult to measure developer experience and permit complexity factors.

If we assume that factors such as these emerged as statistically dominant contributors to viability, there are important implications. In effect, these indicators, if embedded in bid evaluation schemes, would become barriers to entry. Basing viability measures on past development inevitably confers an "incumbent advantage." This advantage is probably realistic and appropriate as long as it is not too large. The challenge in designing bid evaluation systems is to balance the overall viability weight against other factors. The trade-off is between relying too heavily on experience factors compared to underestimating the risk and consequences of project failures.

An alternative approach favored by some utilities addresses project viability risks by establishing damage payments for projects that fail to meet development milestones. Often, the utility requires a schedule of deposits that can be used to compensate it in the case of failed development. For example, a recent stipulation on competitive bidding adopted by New Jersey mandates that winning bidders deposit a total of $18/kW by the time they are scheduled to come on-line (New Jersey, 1988). This money is returned when the project begins operation. The deposits are timed according to an expected schedule of development that is known in advance. Failure to meet the schedule can result in a loss of up to half the deposits. Additional delays are possible, but there must be additional payment.

The approach adopted by New Jersey relies on insurance mechanisms to reduce project viability risk and is a useful supplement to the probability of success approach. If viability were a serious problem, then the linear damage schedule would not provide compensation for what would probably be non-linearly increasing costs. There is, of course, some arbitrariness in setting the level of damages and allocating them to specific stages in the development process. Simulation studies of alternative replacement power costs as a function of lead time might provide better estimates. However, this approach might actually impede development if the resulting damage requirements were too high. The price of insurance may end up costing more than the expected outcome with some failures.

The use of "bait and switch" or "holdup" tactics on the part of bidders is the ultimate trap that the utility must avoid as it attempts to ensure viable development. This phenomenon has been observed in Department of Defense procurements for new weapons systems. The winning bidder obtains the contract by offering a low price. At some point, the bidder suddenly discovers

5. METHODS FOR EVALUATING DISPATCHABILITY

5.1 Overview

Dispatchability is one of the most important operational features that private suppliers can provide to electric utilities. The utility is obliged to follow load fluctuations by varying the output of its plants. Many engineering and contractual constraints limit the operational flexibility of existing utility resources. Nuclear plants are typically designed to operate at maximum capacity. It is expensive to try to vary their output and any output variations that can be achieved are relatively small and slow. Qualifying Facilities (QF) that sell under PURPA regulations are also inflexible. The utility's obligation to purchase QF output at all times makes these resources "must run." Unless there are specific contractual provisions for curtailment of QF production during low load periods, utilities with large amounts of QF capacity and nuclear plants can experience "minimum load" problems. Minimum load problems occur when "must-run" generation exceeds load. Definitions of this condition vary and its degree of severity has been disputed in particular circumstances. Nonetheless, the existence of such a problem is a very good indicator that dispatchable resources, (i.e., those that can follow load) can be quite valuable.

In this chapter we examine how dispatchability has been defined and valued by utilities and analyze how it has been incorporated in bid evaluation systems. We focus on contrasting approaches: 1) unbundling of the component features of dispatchability as part of an "open" bid evaluation system, which has been proposed by Pacific Gas and Electric (PG&E), and 2) Virginia Power's approach, which virtually requires projects to be dispatchable and evaluates the value of dispatchability using dynamic optimization techniques that attempt to capture the non-linear dependencies of the value of each project relative to all other projects. PG&E's proposed bid evaluation system includes explicit linear values for varying degrees of operational flexibility based on the utility's analysis of the differential value of these features. PG&E's unbundling of component features of dispatchability also provides a useful conceptual framework for our discussion (see Section 5.3). It is worth noting that application of this unbundling approach as part of a linear evaluation system introduces approximations to value that may be extreme.

Virginia Power's (VP) approach is potentially more accurate, although it is less transparent to bidders (and regulators) than PG&E's ''open'' scoring system. We analyze VP's approach in some detail because its bid evaluation system is less transparent. In sections 5.4 and 5.5, we describe VP's auction and the optimization problem, review solution methods, and develop a simulation strategy for studying Virginia Power's auction using publicly available data.

5.2 Power System Operational Characteristics and Planning

The requirement that resource output follow instantaneous variations in load is a fundamental characteristic of electric power systems. Supply balances load by definition. However, it is important for utilities to segment those components of the load matching process that can be reflected in contractual terms because it can improve the value and efficiency of transactions between private suppliers and utilities. We examine the operation of power systems in some detail in order to understand the various operational elements of the load-matching process. Focusing on the different time scales that are involved in making dispatch decisions provides a useful analytical framework. Figure 5-1 illustrates the load-matching problem for Southern

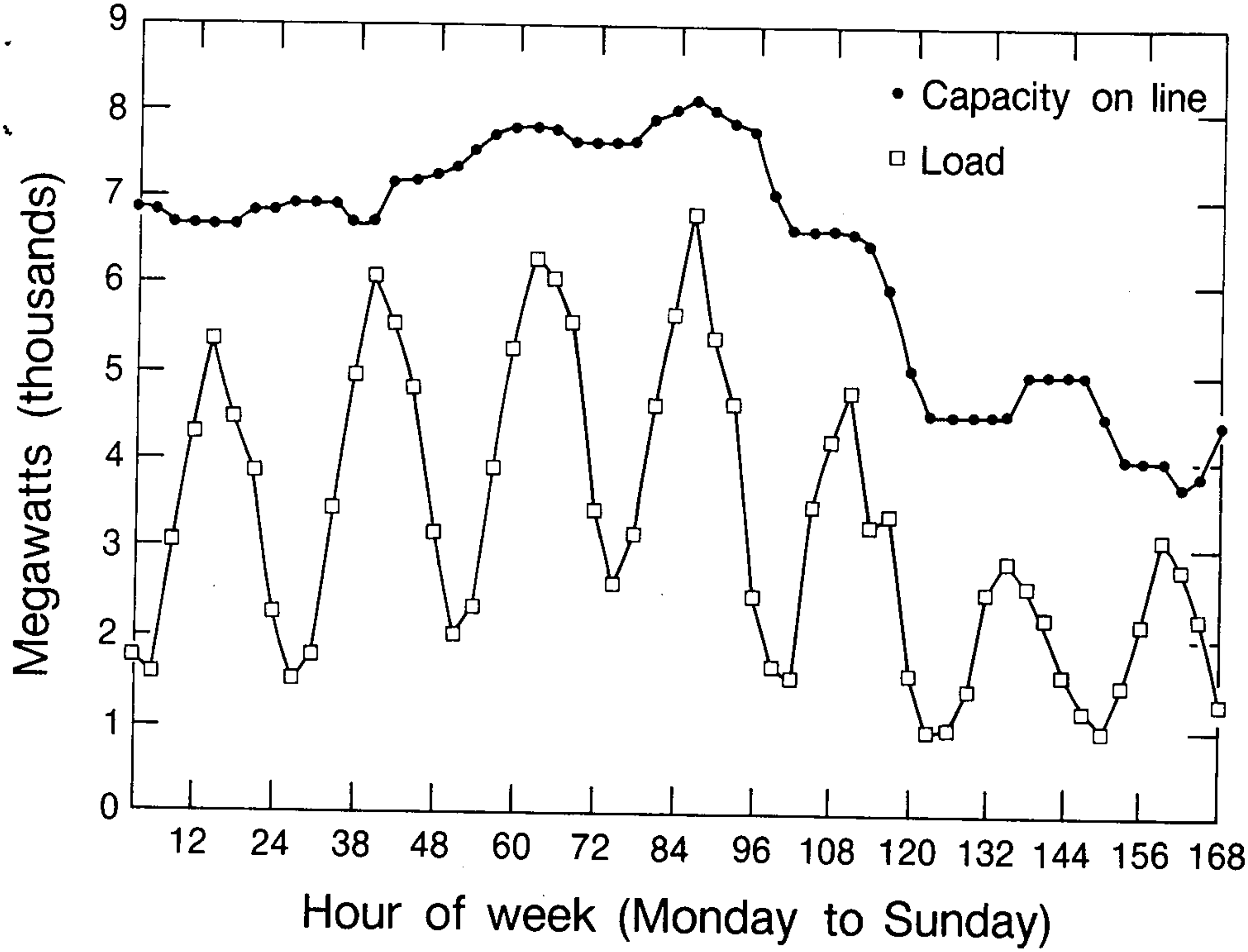

Figure 5-1 shows nameplate capacity of SCE's committed oil/gas units for one summer week in 1984 as well as the load that these units must meet. Unit commitment does not follow daily fluctuations in load.

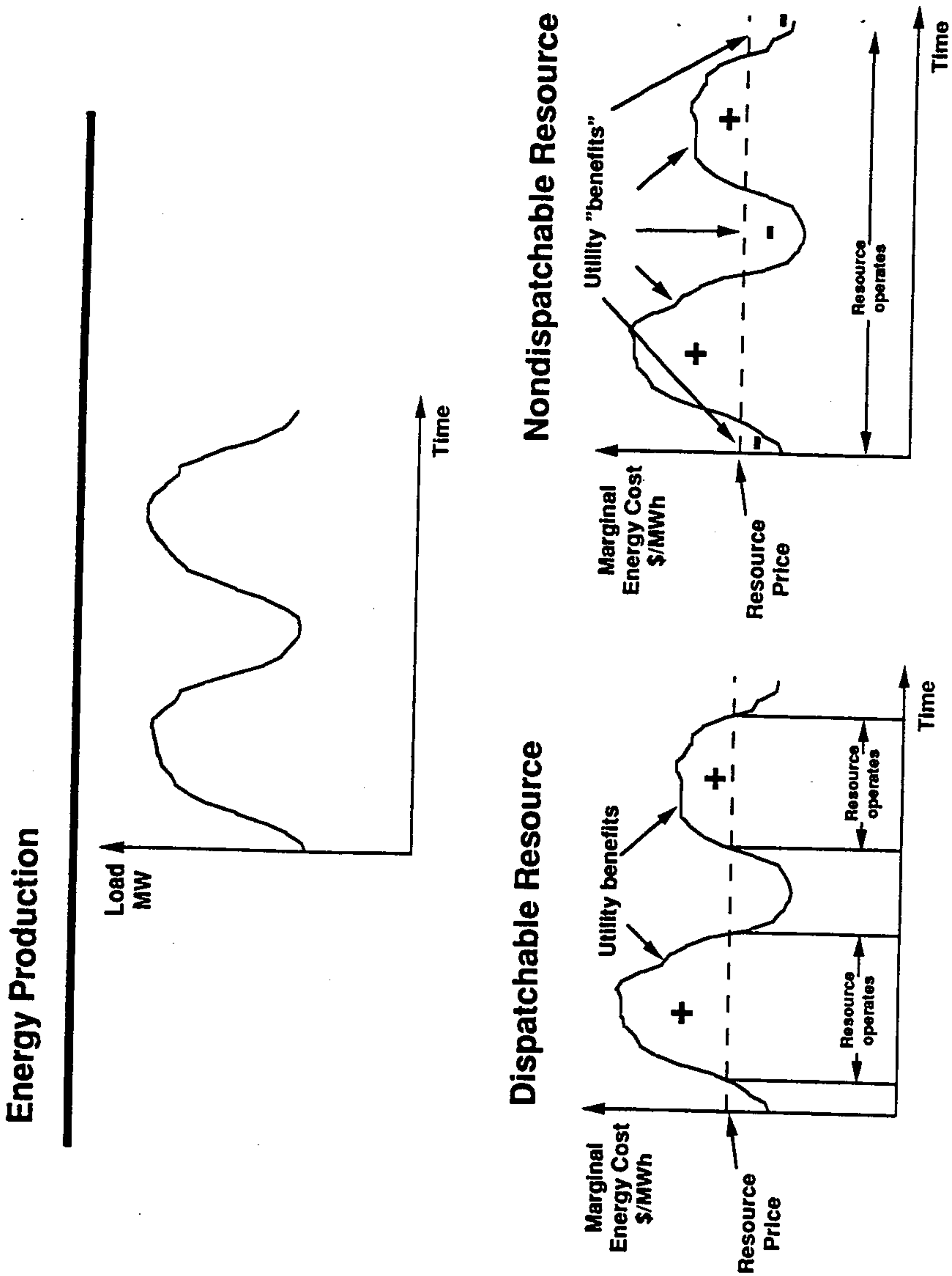

Figure 5-2 shows relative benefits to utility of resources that are dispatchable compared to resources that are "must-run" and not dispatchable. Must-run resources can have negative benefits during low cost periods. Source: Putnam, Hayes, & Bartlett, California Utilities Bidding Workshop, December 1988.

Table 5-1. The inefficiency of linear prices for a large-scale auction: An illustrative example.

(1) Option	(2) Quantity	(3) Value	(4) Price	(5) Bid 1	(6) Bid 2
Value of Dispatchability					
Option #1: Manual Dispatch					
	500 MW	1.25	1.25		
	1000 MW	1.20			
	1500 MW	1.10		1500 MW	
Option #2: Curtailment					
	500 MW	1.06	1.06		
	1000 MW	1.05			
	1500 MW	1.04			1500 MW
Hypothetical Results					
Option #1: Manual Dispatch					
Cost[a]				1875	
Value[b]				1650	
Inefficiency				13.6%	
Option #2: Curtailment					
Cost					1590
Value					1560
Inefficiency					1.9%

Notes:

[a] Cost calculated by multiplying price times quantity bid.

[b] Value calculated by multiplying value times quantity bid.

We then analyze what happens if the actual results of the auction differ from the utility's implicit assumptions that are reflected in its value assignments for curtailable and manual dispatch. We calculate the inefficiencies for the two extreme cases: situations in which all winning bidders offer manual dispatch or curtailment. For simplicity, all costs and values are calculated as the product of the quantity supplied and the corresponding multiplier. A rough estimate of the inefficiency of the outcome is just the percentage excess of cost over value. The inefficiencies are large for the manual dispatch case: linear pricing results in costs that are 13.6% greater than the value of these features. The inefficiencies are much smaller for the curtailment example (about 1.9%). The illustrative results from Table 5-1 show that linear pricing is inefficient if value changes in a non-linear fashion. Non-linear values are likely when incremental capacity additions are large relative to the existing system. Our example is highly stylized and simplified; a much more detailed analysis would be required to assess the actual inefficiencies of linear pricing.

bidding RFP and the computational conventions used in EGEAS. VP allows bidders to offer levelized capacity prices, which is similar to the financial convention used in EGEAS to compute the fixed costs of generic alternatives. The results of VP's conventional capacity expansion analysis are useful because they provide some insights on the likely outcomes of the RFP evaluation.

EGEAS has three options available to the user in solving optimal expansion problems. The most accurate is based on dynamic programming techniques. In this approach each alternative is simulated in the production costing element of the program, and the total revenue requirements are computed (both fixed and variable costs). Unfortunately, computation time increases exponentially as the number of alternatives examined increases. In the conventional expansion analysis framework, the utility typically uses a small set of technology types from which it can choose as many plants as it likes. The key to computational tractability is the limit on the number of technology types. VP uses this approach in its analysis and considers only four generation options: (1) combustion turbines, (2) combined cycle, (3) fluidized bed coal, and (4) large-scale pulverized coal with scrubbers. VP's analysis showed that a total of 1400 MW of combustion turbines should be added in 1993 and 1994 and 370 MW of combined cycle facilities in 1993. VP projects that it will need an additional pulverized coal plant around 1996.

The major difference between the conventional expansion problem and large-scale bid evaluation is the number of alternatives that are considered. The response to VP's RFP produced 95 bids. Each of these projects had its own capacity, capacity price, and variable cost. It is computationally infeasible to evaluate this number of alternatives using dynamic programming. In fact, EGEAS imposes a limit of ten alternatives for dynamic programming. Therefore, we must rely on other available EGEAS solution techniques: linear programming or the Benders decomposition approach. Both options have one fundamental limitation: they ignore the integer constraints on capacity that are incorporated in dynamic programming. The integer constraint means that additional plants are chosen or they are not; there is no intermediate position. Ignoring the integer constraint means that the optimal plan will include fractional plants. While this is an annoying feature, it is not fatal. In a practical sense it is also unavoidable. The only analytic choice is whether to use linear programming or the Benders decomposition.

The Benders decomposition approach is the preferred solution technique available in EGEAS because the linear programming (LP) approach is uninteresting for dispatchable projects. The LP approach requires that the user specify a capacity factor (i.e., level of output) in advance of the optimization. This eliminates the whole dispatch simulation, and so is essentially useless for evaluating bids that only offer dispatchable power. Benders incorporates standard production simulation calculations and thus can be used to compare the fixed versus variable cost trade-off for each bid and across bids. To summarize, we conclude that EGEAS can be used to evaluate bids in a large-scale auction with features similar to Virginia Power's RFP and that the Benders decomposition approach can give useful information on the desirability of offers. However, we will need a method to deal with the fractional acceptance problem in order to interpret the results.

cancellation of a proposed nuclear power plant and it is unclear if it is consistent with VP's current load forecast (VCC, 1984). We also had to make some assumptions regarding the modeling of VP's power purchase contracts with other utilities. We represented the two long-term purchases from Indiana (i.e., Rockport and Hoosier Energy Co-operative) as thermal plants that were dispatched at their variable cost. Other purchases from utilities were represented as peak shaving, while QF purchases were treated as must-run baseload energy.

We then calibrated our EGEAS simulation of the Virginia Power system to the results provided by VP in its avoided cost filing, based on a PROMOD production cost simulation. Table 5-2 shows the results for 1990. We have aggregated generation by fuel type. The generation levels of baseload resources, such as nuclear, hydro and the Mt. Storm coal plant, are quite similar. However, there is less agreement on the generation levels of VP's marginal resources. For example, the in-system coal plants, which have relatively high capacity factors, are about 7% low in EGEAS. The total of Rockport, Hoosier and Other Purchase and Interchange (P&I) shows about the same energy in both cases. However, the relatively low-cost Rockport and Hoosier purchases supply less energy in our EGEAS simulation. This result, along with the in-system coal results, suggests that our load shapes may have too little energy in the intermediate load segment and too much in the higher load segments.

Table 5-2. EGEAS Calibration to Virginia Power's avoided cost forecast (1990).

Plant or Fuel Category	Virginia Power forecast[a] (GWh)	EGEAS results (GWh)	EGEAS Deviation from PROMOD
Nuclear	19,975	19,257	-3.6%
Mt. Storm coal plant	11,101	11,057	-0.4%
In-system Coal	14,878	13,868	-6.8%
Oil/Gas	959	1,113	16.0%
Hydro	746	737	-1.2%
Pumped Storage	1,477	1,491	+1.0%
Rockport/Hoosier	5,126	3,652	-28.8%
Other Purchase &Interchange	7,334	8,750	+19.3%

Notes: [a] Virginia Power forecast taken from PROMOD production cost simulation.

Our EGEAS calibration is reasonably consistent with VP's reporting in the avoided cost filing of its long-term capacity needs. As part of its long term methodology, VP ran the EGEAS dynamic programming optimization to determine a hypothetical least cost expansion plan. This analysis is suggestive about the type of long-term capacity that VP might need. VP focused on four technologies: combustion turbines, combined cycle, conventional pulverized coal, and fluidized bed coal. We show VP's results along with the utility's technology cost assumptions in Table 5-3. The basic message of these results is that only oil and gas technologies are optimal to add in the period up to 1995 (e.g., combustion turbines and combined cycle).

Table 5-4. LBL simulation of VP's expansion plan using EGEAS.

Year	Combined Cycle (MW)	Large Coal (MW)	Waste Coal (MW)	Maximum Combined Cycle Capacity Factor (%)
1988				
1989				
1990	300			28.4
1991	600			31.3
1992			80	27.4
1993	1200			45.6
1994	300			55.6
1995	300			57.7
1996	300		80	54.1
1997	300			57.0
1998				59.5
1999	300	1050		60.6
2000		350		59.8
2001		350		56.9
2002		350		56.4
2003		350		55.2
2004		350		53.9
2005	300	350		54.0
2006		350	80	51.9
2007		700		37.0
2008		700		26.1
2009	900			31.6
2010	300	700		30.6
2011	300	350		32.4
2012	700	300	80	32.3

Notes: Our EGEAS simulation used dynamic programming techniques to solve for optimal expansion plan.

We also show the maximum capacity factor of combined cycle plants in each year, which provides some additional insights into the optimization results (see last column of Table 5-4). The capacity factor of combined cycle units is an indirect indicator of system needs. Capacity factor is defined as actual output divided by the theoretical maximum for a given unit. Because of outages and maintenance, units never obtain this theoretical maximum. Units will have a characteristic range of performance depending on which segment of the load curve they serve. Baseload units have high capacity factors while peaking units have low capacity factors and intermediate units fall in the middle. A simple static analysis tool called the screening curve is often used to define these ranges for a given load curve and technology cost characteristics.

Table 5-5. **Summary of Virginia Power's actual bids (March 1988 RFP).**

Fuel Type	Number of Bids	Total MW	Avg. Capacity (MW)
Coal	41	8212	200
Coal Waste	13	1068	82
Gas & Oil	24	4843	202
Other	17	530	31

We make the a priori assumption that bids are distributed lognormally, which is a common distribution in economics (Aitchison and Brown, 1957). We apply this assumption to variable price, capacity and fixed costs. For the distribution of variable costs, we choose a mean value that is consistent with VP's expected fuel costs. For waste coal, we use the variable costs of the Mt. Storm plant as representative of the expected value. The variances for each of the fuel cost distributions are chosen to produce a range that would capture both the highest and lowest values we might encounter. Once we have chosen a set of values for variable cost which spans the probability density and gives the a priori number of bids that we want, we must match them to capacities and fixed costs. Our procedure is designed to insure that there is no correlation between variable cost and capacity and fixed cost. This randomization is an explicit modelling choice. It is also possible to apply specific correlations at this level if desired, but we have not elected to take this approach.

We next generate a distribution of capacities, using the same procedure that was applied to the variable cost distributions. We set the mean value for each fuel type using the average value of capacity bid (see Table 5-5). However, it is difficult to create a reasonable range of capacities with these mean values and the lognormal distribution. The basic problem is that this procedure yields a few very large capacity bids (600-1100 MW) and a fair number of bids below 20 MW. We opt for excluding these extremes. To achieve this bound we chop off the tails of the distributions on capacity. The result is a range of bids that lies between 20 and 400 MW. There are other procedures that can be used, but none are elegant or well-motivated.

Finally, we capture scale economies in capital costs by applying an exponential scaling coefficient that links the capacity of a bid to its fixed costs. Thus, on average, fixed costs diminish with capacity, although there is still randomization in our procedure that assigns a fixed cost price to each capacity bid. Table 5-6 summarizes the results of these bid creation procedures and gives the number of bids for each technology and fuel type and the average values and standard deviations for capacity, fixed cost, and variable cost (see Appendix D for a complete list of bids). It should be noted that any number of bids can be created in this fashion by specifying parameters of the distribution.

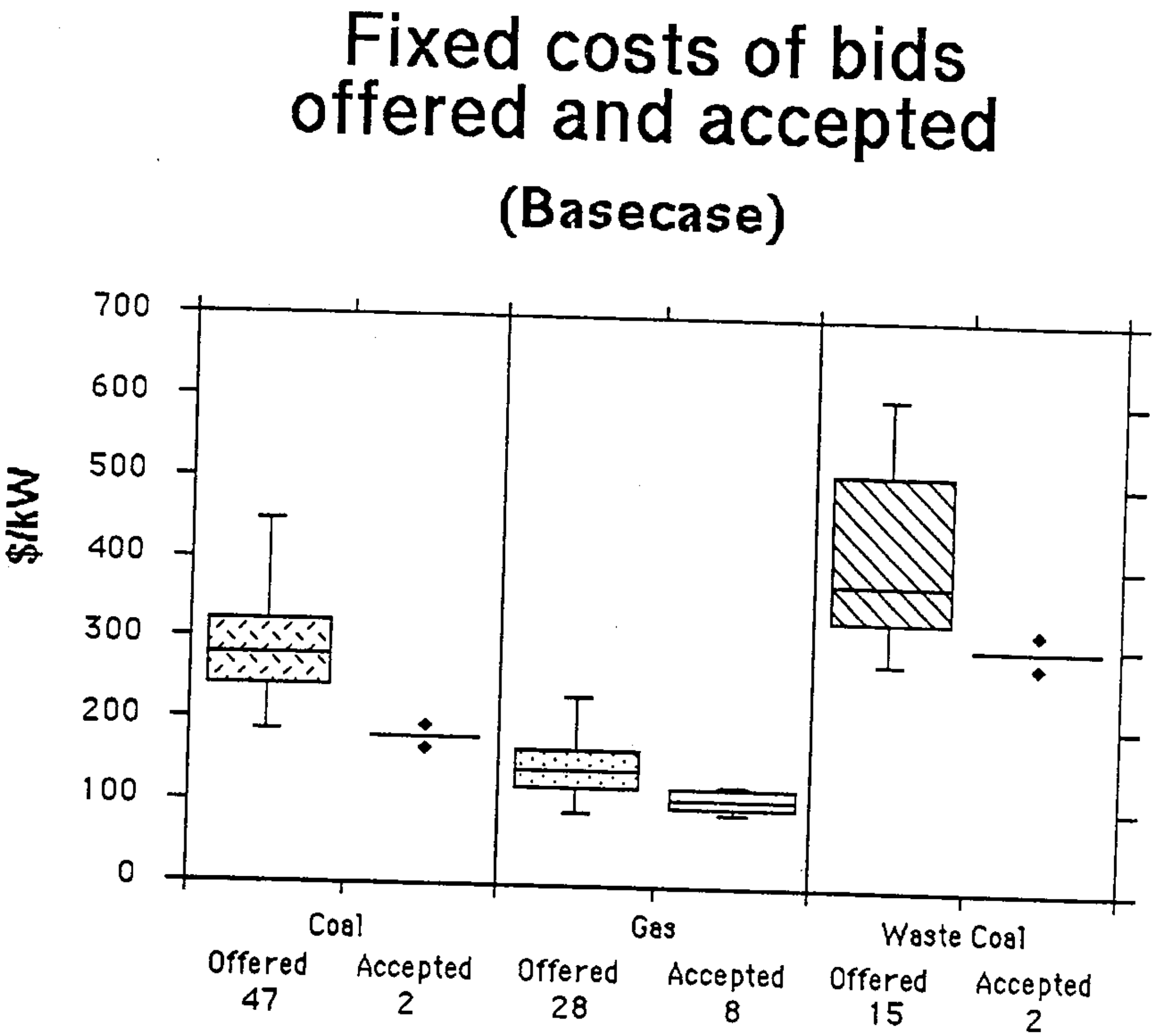

Figure 5-3 shows the distribution of fixed costs ($/kW-year) of all of the bids that were submitted as well as winning bids for each of the three technologies in LBL's simulation of a large-scale dispatchable auction. We plot fixed cost values for the minimum, maximum, median and 25% and 75% quartile bids; accepted bids are shown as data points for coal and waste coal because only 2 bids were accepted for each technology.

these factors tend to favor coal. We have no way to specify how VP might embody the non-price factors in an evaluation system that is compatible with their treatment of price and the dispatchability requirement. This is a difficult problem even if we had some kind of point system to represent the non-price scores of bids. The difficulty arises because the optimization approach does not yield a rank ordering of bids. Bids are either accepted or rejected. There are a number of approaches that can be taken to the problem of integrating non-price factors with optimization. We used two different methods, both of which monetize the non-price factors in particular ways.

Our first approach focused on VP's announced preference for solid fuel projects. As Table 5-5 shows, bidders responded to this announced preference by offering twice the capacity of non-gas projects as compared to gas-fired. The RFP describes this preference in terms of "stable" prices. We can interpret this to mean that the gas price forecast contained in the RFP is somehow lower than what VP really expects gas to cost. If you think that gas costs will actually be high, then it is worth paying higher capacity costs for coal. We model this by re-running our simulation using the DRI "high" gas forecast, which is almost twice as high as VP's basecase assumptions.

Our second approach, which is not entirely distinct conceptually from the first, emphasized the indigenous economic benefits of local coal projects. Coal mining represents an important industry for the region and additional power development based on these resources would have beneficial effects on the local economy. The RFP also identified this factor separately from fuel price considerations. VP's announcement of winning bids also contained information about expected employment impacts of the selected projects. To model this factor, we assumed that all coal and coal waste bids are given a $40/kW credit in the tournament; capacity bids were reduced by that amount to reflect the economic benefits to the local economy. The value of the credit was chosen arbitrarily, but as results discussed below indicate, it seems to be in the appropriate range. In this sensitivity case, we used VP's fuel cost assumption along with our estimated credit to reflect the preference for coal. The results of both sensitivity cases are shown in Table 5-8.

Table 5-8. LBL simulation of VP-type auction: Sensitivity analysis.

Fuel Type	High Gas Price (MW)	$40/kW Coal Credit (MW)
Coal	1095	862
Coal Waste	203	264
Gas	1078	1254
Total	2376	2380

Broadly speaking, the results in Table 5-8 show that either a high gas price forecast or a substantial dollar credit to coal-fired capacity will bring the optimization results more into line with VP's actual choices with respect to the market share of gas-fired capacity. The particular values used in these tournaments are not particularly precise estimates of the implied value given

Table 5-9. An estimate of the cost and value of insurance in selecting VP's future resource mix.

Year	(1) Incremental Costs (Million $) Basecase Gas Price Forecast Gas Mix	(2) Basecase Gas Price Forecast Coal Mix	(3) High Gas Price Forecast Gas Mix	(4) High Gas Price Forecast Coal Mix	(5) Difference for Basecase Gas Forecast	(6) Difference for High Gas Price Forecast
1989	733	733	750	750	0	0
1990	830	844	935	952	14	-17
1991	948	948	1105	1106	1	-2
1992	1047	1085	1267	1275	38	-8
1993	1500	1657	1958	1927	158	30
1994	1850	1900	2381	2278	49	104
1995	2032	2080	2754	2611	47	144
1996	2199	2238	3148	2956	38	193
1997	2403	2436	3595	3353	32	243
1998	2604	2627	4020	3719	22	302
1999	2911	2926	5091	4679	14	413
2000	3241	3239	5979	5474	-3	506
2001	3512	3490	6636	6050	-23	587
2002	3892	3847	7622	6940	-46	683
2003	4306	4237	8647	7873	-70	775
2004	4784	4689	9785	8918	-96	868
2005	5371	5247	11229	10255	-125	975
				NPV	152	1661

Year	(1) Total Costs (Million $) Basecase Gas Price Forecast Gas Mix	(2) Basecase Gas Price Forecast Coal Mix	(3) High Gas Price Forecast Gas Mix	(4) High Gas Price Forecast Coal Mix	(5) % Difference for Basecase Gas Forecast	(6) % Difference for High Gas Price Forecast
1989	2949	2949	2966	2966	0.0%	0.0%
1990	3046	3060	3151	3168	0.5%	-0.5%
1991	3164	3164	3321	3322	0.0%	-0.1%
1992	3263	3301	3483	3491	1.2%	-0.2%
1993	3716	3873	4174	4143	4.1%	0.7%
1994	4066	4116	4597	4494	1.2%	2.3%
1995	4248	4296	4970	4827	1.1%	2.9%
1996	4415	4454	5364	5172	0.9%	3.6%
1997	4619	4652	5811	5569	0.7%	4.2%
1998	4820	4843	6236	5935	0.5%	4.8%
1999	5127	5142	7307	6895	0.3%	5.6%
2000	5457	5455	8195	7690	-0.0%	6.2%
2001	5728	5706	8852	8266	-0.4%	6.6%
2002	6108	6063	9838	9156	-0.8%	6.9%
2003	6522	6453	10863	10089	-1.1%	7.1%
2004	7000	6905	12001	11134	-1.4%	7.2%
2005	7587	7463	13445	12471	-1.7%	7.2%
NPV	33854	34006	43483	41822	0.4%	3.8%

average fixed and variable costs. A useful improvement would be better data collection in this area.

The most interesting questions raised by these experiments are methodological. We will couch our conclusions about these optimization studies in those terms, because the methodological issues raise questions of more general interest. One set of questions raised by this simulation is whether the optimization algorithms produce stable results. Because these are large scale problems, it is difficult to develop an intuitive feel for the results. Trusting a computational "black box" to give sensible answers may itself not be a sensible strategy. Careful inspection of the final outcome of our tournaments gives some confidence about stability. For example, in our sensitivity cases, we varied the underlying economics for some bids by altering the variable costs in the high gas price case and fixed costs in the coal credit case. We found that plants that are selected change in a reasonable fashion in these alternative cases (see Table 5-11). Roughly 70% of the capacity of the winning bidders is in a core group that wins under all three scenarios. Within a fuel group, the winners tend to be bidders with larger capacity, probably because of our assumptions regarding scale economies. Some bids are losers in all three cases and are not shown in this table (see Appendix E). In addition, there are certain projects that only win in one or two cases; these marginal bidders are our competitive fringe. In only a few cases do we select an alternative that only shows up once. When that occurs it is usually possible to identify the bid as high cost compared to the core set of winners. Thus, we often end up choosing among the same subset of alternative bids.

non-price factors, then each such factor would have to be monetized essentially as an adjustment to the fixed or variable costs of bids. While such an approach is not out of the question, it would involve a considerable extension of methods now being used. The alternative to monetizing the non-price factors would be a procedure for turning the optimization results into a point system. Use of the dual multipliers, which are discussed below, is one way a rank ordering might be constructed.

The analysis thus far has been conducted largely from the viewpoint of the utility that is buying from bidders. Is there anything in this kind of approach that could help bidders? The answer is a qualified yes. Simulating a competition can help define cost and price goals that are necessary for success. It is clear from first principles that the average bid will lose unless the number of bids is small relative to the need. In considering whether to participate in an auction, the potential bidder must assess his own potential price with the distribution of prices that he thinks will be offered by others. This essentially requires a model, implicit or explicit, of the distribution of bids. Our simulation starts with such a model and then calculates, for those assumptions, how much better than the average bid a winning bid must be. For this exercise to be helpful to the bidder, he must have some confidence in the estimate of the bid distribution.

If a bidder has gotten far enough along with his competitive assessment to try fine-tuning his bid, then simulations such as these have something to offer. For example, one output of the optimization is a "dual price" for each accepted bid. The dual price represents how much the buyer (utility) would be willing to pay for an additional unit of the same bid. It is the marginal value of the bid. The dual price is expressed in EGEAS as discounted dollars for each accepted project. It is not separated into fixed and variable elements. For strategic purposes the bidder would want to know something about how to structure his offer in those terms. In our bid distributions there is substantially more variance in the fixed cost part of the bids than the variable part (see Table 5-6). The dual prices in this case can just be divided by capacity to get a measure of value per kW. If the dual multiplier is low, the bid is marginal. If it is high the bidder has leverage to raise his price offer. Raising the fixed payment component will not affect the dispatch of the project. Raising the variable component will reduce production unless the bid is base loaded (which would probably only apply to waste coal).

The dual multipliers are of only limited value to the bidder, because the bid distribution is not known with very much accuracy. The utility, on the other hand, does know that distribution and thus can use the dual multipliers to convert the optimization outcome to a cardinal ordering (i.e., "points"). The utility can also use them as a guide for negotiations with bidders: making price concessions to bidders when dual prices are high and refusing to do so when dual prices are low. However, any major price concessions may require re-running the entire tournament.

Finally, it is useful to compare the finely discriminated taxonomy of dispatchability proposed by PG&E with the optimization analysis. The use of EGEAS suppresses many of the distinctions made possible in PG&E's static mode. The production simulation component of EGEAS does not model unit commitment explicitly. It is impossible to tell at this stage how much is lost by this, or what approximations might be used to improve the analysis. Conversely, PG&E's static approach cannot address the interactions among bids and the potential inefficiency that results from neglecting them. In principle, the optimization approach is better if

6. DIFFERENTIAL EFFECTS OF BID EVALUATION SYSTEMS: ILLUSTRATIVE CALCULATIONS

6.1 Overview

In this chapter, we illustrate the differences among four proposed bid evaluation systems by scoring the same set of eight bids in hypothetical auctions. It is not possible to perform an exercise of this kind in a completely neutral fashion because the offers that will be made in any particular situation will inevitably be local in two ways. First, bids will reflect local resource opportunities and regional opportunities for power development are not uniform. Second, bidders respond to incentives created by the given set of evaluation criteria. Therefore, bids are shaped by the rules under which they will be scored. A further practical limitation is that bids are not made public at the level of detail required to score projects. Thus, there is no readily available pool from which a sample can be drawn.

Despite these limitations, we believe that much can be learned from a comparison of utility bidding systems as they would operate in evaluating actual projects. We rely on hypothetical bids submitted in a bidding game formulated and conducted by the California investor-owned utilities at a workshop held in San Francisco in February, 1989. The purpose of the workshop was to acquaint the community of regulators and private suppliers with the multi-attribute bid evaluation system being proposed by the utilities. To simulate an auction, workshop organizers provided resource characterizations for five projects. Participants were assigned to one of ten teams (two teams per project) and each team then worked in isolation to develop a bid for its project. Some attributes of a bid were inherent to the project, although, in many cases, project attributes were determined by the team players.

We had to make some generalizations regarding the underlying resource data in order to adapt the California bidding workshop data to our purposes. Five technologies were competing in the California workshop: gas-fired co-generation, gas-fired combined cycle, biomass, geothermal and small hydro. Not all of the resources were specified to be equally economic, nor are all of them available nationally. The most localized is geothermal. California and Nevada are the only states with commercial geothermal power production. Because we cannot literally assume that projects of this kind are relevant nationally, we interpret the data as representative of capital-intensive, low-variable cost technology. In essence, the geothermal project serves as a proxy for a coal-fired project. The fixed and variable costs of the geothermal projects are quite comparable to the ranges used for these values in our Virginia Power simulations of coal technology. We also excluded the small hydro project from our simulation. The scale of this project is an order of magnitude smaller than all others (i.e., 2 MW), and its resource economics were much more favorable. This makes it uninteresting for the competition,

In the following sections, we give brief descriptions of each power project and then score each project under bid evaluation systems proposed by four utilities/states.[1] We identify those

[1] Note that project bids are scored based on draft RFP's proposed by utilities; the scoring system of the final RFPs approved by PUCs in New York and Massachusetts differ somewhat from the utility's initial proposals.

Table 6-1(b). Characteristics of generic bids: Discretionary options.

Option	Combined Cycle 1	Combined Cycle 2	Cogeneration 1	Cogeneration 2	Geothermal 1	Geothermal 2	Biomass 1	Biomass 2
Fixed Price ($/kw-yr)	$229	$160	$100	$5	$316	$235	$239	$250
Escalation Method[a]	C	E	E	E	C	E	C	C
Variable Price ($/MWh)	22.1	23.6/20.6	23.8	62.5	20.1	19.0	12.9	12.9
Escalation Method								
% GNP	30	10	9	100				
% Gas	70	90	91	0				
Curtailable/[b] Dispatchability	M	M	1500	1500	1500	1500	M	M
Start Date Flex[c]	A/D	No	D	D	No	A/D	D	D
Site Secured	Yes	Yes	Yes	Yes	No	No	No	Yes
Failure Security	0	0	$500K	0	0	0	No	$300K

Notes:

[a] Fixed Price Escalation method: C = constant over term of agreement; E = escalates at rate of inflation

[b] Dispatchability/Curtailabiliy option: M = Manual dispatch; 1500 refers to number of hours that plant can be curtailed

[c] Start date flexibility: A = two-year start date acceleration; D = two-year deferral in start date

The biomass project was a 15-MW facility sited at a remote rural or agricultural location with an installed cost of $1027/kW. The project was initially structured to have 75% debt and to offer a fixed capacity price of $239/kW-yr and a variable price of $12.90/MWh. At these prices the return on equity (ROE) is expected to be 20%. The two bidders made no change to the proposed variable prices, but Bidder 2 decided to increase the capacity price by about 4.5% ($250/kw-yr). Both teams made adjustments to non-price factors. For example, both teams chose to be dispatched manually and offer the possibility of being deferred at the utility's option for two years. Bidder 1 did not secure the site or offer any failure security, while Bidder 2 secured the site and offered failure security. The underlying resource economics of this project (as specified) are so favorable that it always wins under any set of rules.

The gas-fired cogeneration project is assumed to be a 49-MW facility located at an urban industrial site with an installed cost of $1388/kW. These costs appear to be high for cogeneration projects and may include equipment to meet very rigid NOx control requirements. The project is structured to have 80% debt. The revenue from steam sales will cover O&M costs but for Bidder 2. Bidder 2 chose an escalating capacity price, starting at $160/kW-yr and offered a time-differentiated variable price (2% above the base case on-peak and 11% below off-peak).

6.3 Competitive Results For Four Evaluation Systems

Table 6-2 summarizes the results of evaluating the eight bids in four scoring systems. We include the system proposed by the California utilities because this was the context in which the bids were developed, rather than the approach that has been adopted by the California Public Utility Commission (see section 3.3). Appendix F provides a more detailed description of the decision rules and criteria used to score the eight projects for the other three utilities (Boston Edison, Niagara Mohawk, and Orange and Rockland). Table 6-2 lists the size of each project, its rank strictly by price criteria, and its rank when both price and non-price factors are taken into account. In addition, we have computed the mean and standard deviation of the price score as well as the combined score of all other non-price factors. These statistics allow us to develop a sense of the real weight given to the price and non-price factors in the proposed scoring systems. Our overview of utility bid scoring systems presented in Chapter 3 provided only the nominal weighting applied to the various factors. This hypothetical auction allows us to see, for a given set of bids, what the real weights turn out to be. It should be emphasized that any analysis of the real weights of a utility's scoring system is limited by the actual or hypothetical bids evaluated in that auction. Conclusions about real weights are robust only to the degree that bids are representative.

Table 6-2. Ranking of generic bids in four utility bid evaluation systems

Project	Size (MW)	Price Rank	ORU	BECO	NMPC	CA
Biomass #1	15	1	2	2	1	1
Biomass #2	15	2	1	1	2	2
Combined Cycle #1	45	3	3	5	4	3
Combined Cycle #2	45	4	4	3	3	6
Geothermal #2	45	5	5	4	5	4
Geothermal #1	45	6	6	7	6	5
Cogeneration #2	49	7	7	6	7	7
Cogeneration #1	49	8	8	8	8	8
Price Score						
Mean			10.8	16.5	140.3	
Std. Deviation			6.9	10.3	87.9	
Non-Price Score						
Mean			35.1	84.9	204.9	
Std. Deviation			3.2	18.4	40.2	

Of the four systems, the ranking of projects in ORU's scoring system most closely parallels the price rank (Table 6-2). Only the order for the two biomass bids is reversed. The summary

Table 6-3. Project bid scores in Boston Edison's bid evaluation system

	Maximum Score	Combined Cycle #1	Combined Cycle #2	Gas-Fired Cogen #1	Gas-Fired Cogen #2	Geothermal #1	Geothermal #2	Biomass #1	Biomass #2
Price Factor	100	17	15	0	7	14	15	33	31
Economic Confidence Factors									
Breakeven Period	30	20	30	8	15	17	30	30	27
Front Load Security	20	0	20	0	0	0	20	20	20
Project Development Confidence Factors									
Tech./Environ. Feasibility	10	10	10	10	10	10	10	9	9
Project team experience	6	6	6	6	6	6	6	2	2
Level of Development									
Siting	10	10	10	10	10	0	0	0	10
Design & Engineering	4	2	2	2	2	2	2	2	2
Permit & Licensing	6	3	3	3	3	3	3	3	3
Financing	6	4	4	4	4	4	4	4	4
Thermal Energy	2	0	0	0	0	2	2	2	2
Construct./Oper.	2	0	0	0	0	0	0	0	0
Additional Contract Deposit	4	0	0	4	0	0	0	0	4
Operational Longevity Confidence Factor									
Debt & Operating Coverages	6	0	0	4	4	0	0	1	1
Fuel Supply	6	0	0	0	0	0	0	0	0
Maintenance: O&M Contract	2	0	0	0	0	0	0	0	0
Optional Operating Security	6	0	0	0	0	0	0	0	0
System Optimization Factor									
Dispatchability/Interruptibility	10	10	10	8	8	8	8	10	10
Fuel type	10	0	0	0	0	4	4	8	8
Size	2	0	0	0	0	0	0	2	2
Location	4	4	4	4	4	0	0	4	4
Maintenance Scheduled by BECo	4	4	4	4	4	4	4	4	4
PRICE FACTORS	100	17	15	0	7	14	15	33	31
NON-PRICE FACTORS	150	73	103	67	70	60	93	101	112
TOTAL	250	90	118	67	77	74	108	134	143

	Mean	Std. Dev
PRICE FACTORS	16.5	10.3
NON-PRICE FACTORS	84.9	18.4

Table 6-4. Project bid scores in Niagara Mohawk's bid evaluation system.

	Maximum Score	Combined Cycle #1	Combined Cycle #2	Gas Fired Cogen #1	Gas Fired Cogen #2	Geothermal #1	Geothermal #2	Biomass #1	Biomass #2
Price Factor	850	144.5	127.5	0	59.5	119	127.5	280.5	263.5
Economic Risk Factor									
Breakeven Period	50	30	50	0	20	23.3	50	50	46.7
Front Load Security	25	0	25	0	0	0	25	25	25
Success Factor									
Tech./Environ. Feasibility									
Site Acquisition	10	10	10	10	10	0	0	0	10
Design & Engineering	10	6	6	6	6	6	6	6	6
Permit & Licensing	10	5	5	5	5	5	5	5	5
Facility Availability	10	10	10	10	10	10	10	9	9
Level of Development									
Construct./Oper.	2	0	0	0	0	0	0	0	0
Thermal Energy	2	0	0	0	0	2	2	2	2
Financing	6	4	4	4	4	4	4	4	4
Project team experience	6	6	6	6	6	6	6	2	2
Additional Contract Deposit	4	0	0	4	0	0	0	0	4
Economic Development	4	1	1	3	3	3	3	1	1
Longevity Factor									
Fuel Supply	7	7	7	7	7	7	7	3	3
Debt & Operating Coverages	6	0	1	4	4	0	0	1	1
Maintenance: O&M Contract	2	0	0	0	0	0	0	0	0
Optional Operating Security	6	0	0	0	0	0	0	0	0
Operational Factor									
Operations Optimization									
Unit Commitment	14	14	14	6	6	6	6	14	14
Economic Dispatch	20	20	20	8	8	8	8	20	20
Automatic Generation Control	10	0	0	0	0	0	0	0	0
Black Start	6	0	0	0	0	0	0	0	0
Planning Optimization									
Location	4	4	4	4	4	1	1	4	4
Unit Size	3	0	0	0	0	0	0	3	3
Fuel diversity	10	4	4	4	4	6	6	8	8
Fuel Flexibility	8	6	6	6	6	0	0	6	6
Quick Start Ability	5	5	5	0	0	0	0	0	0
Environmental Factor									
Environmental Rating	100	77	77	80	80	51	51	80	80
Environmental Benefit	10	0	0	0	0	0	0	0	0
PRICE FACTORS	850	144.5	127.5	0	59.5	119	127.5	280.5	263.5
NON-PRICE FACTORS	350	209	255	167	183	138.3	190	243	253.7
TOTAL	1200	353.5	382.5	167	242.5	257.3	317.5	523.5	517.2

	Mean	Std. Dev	Coeff of Var
PRICE FACTORS	140.25	87.92	0.63
NON-PRICE FACTORS	204.88	40.21	0.20

We offer a final word of caution regarding our numerical exercise. While the issues of real weights and the differences among evaluation systems are important, the eight bids offered here are only pseudo-data at best. They represent the outcome of a game, and do not involve the kind of real world experience that is necessary to obtain a better fix on the distribution of bid features. It is important to use actual bid distributions to investigate the substantive issues raised here more reliably and systematically.

7. CONCLUSIONS

Competitive bidding for new electric power supplies represents both a major challenge and opportunity. The opportunity is the prospect of innovation and economies that result from competition and increased reliance upon market forces. The challenge lies in managing a highly complex process. In this study we have focused mainly on the challenges associated with implementing bid evaluation systems that take account of price and non-price factors. One recurring theme is the difficulty in designing bid evaluation systems that are both workable and yet capture the complexity of developing meaningful valuations of various electric power attributes. We have discussed several non-price factors (e.g., fuel diversity, fuel choice, environmental impacts, system operational features, development risk) that require additional quantification and, in some cases, fundamental conceptual work. In addition, the benefits of flexible planning should be incorporated into bid evaluation systems (e.g., evaluation of bids under different load growth and fuel price scenarios). In the near term, we believe that a more realistic approach to the trade-off between project viability and pricing terms is the most significant improvement needed in bid evaluation systems.

In a broad sense, problems in designing bid evaluation systems reflect tensions that exist between two fundamental forces that affect the organization of electricity markets: centralization and coordination versus decentralization. Bid evaluation involves centralized utility planning of the kind embodied in the classical capacity expansion problem. The planning issues include a determination of the need for power, the optimal mix of facilities, siting and environmental considerations, and the feasibility of alternatives. However, with the advent of competitive bidding, most of these decisions must be coordinated with business entities that are not under utility control and management. Thus, a new element of decentralized decision-making is added to the planning process, which had been absent previously. Moreover, the objectives of private suppliers are not necessarily consistent with those of utilities. Therefore, contractual mechanisms must be constructed that explicitly determine mutual requirements over long periods of time. Inevitably, issues of risk, uncertainty and moral hazard arise in this context. Finally, national policy issues and priorities (e.g., environmental and national security concerns) may assume a larger role in decisions that affect the acquisition of new electric resources, which adds an additional level of complexity. Decisions about electric power facilities have important consequences for environmental and economic policy. Social concerns about these factors must somehow become a part of the evaluation process.

It is safe to say that no consensus has emerged about how to handle the various elements involved in evaluating bids for new power generation facilities. We are in a period of experimentation. However, it is important to remember the context in which competitive bidding emerged. It was largely out of frustration with traditional methods of planning and regulation that public policy has converged upon bidding. Utilities see the bidding process as a way to limit the risks of investment. Regulators are anxious to avoid experiences with rate shock. Underlying this brave new world of experiments with competition, lies a set of attitudes that emphasize limiting risk. The difficulty that these attitudes create is that there may be no way to eliminate risk for all parties and achieve the benefits of competition.

This contradiction can best be seen in the conflict between the desire to limit the exposure of ratepayers to potential overpayments to suppliers and the financial requirements of tolerant policy toward bidders that offer front-loaded bids. Combining a complex and essentially closed evaluation system with financial accommodations to bidders is an interesting compromise among these objectives. The approach favored by Virginia Power is not the dominant trend at the present time. Rather, "open" systems, in which bidders can self-score their projects, seem to have more appeal to utilities and regulators, although these systems may involve some potential losses in efficiency. In addition, developing more realistic measures of project viability is a key area that needs improvement in the "open" systems.

The role of social policy in competitive bidding is still largely unexplored. We have touched briefly on fuel choice decisions in this context and raised the issue of environmental policy. It seems likely that environmental issues will become increasingly important in the bid evaluation framework. There are many procedural and analytic aspects of these questions which have not been fully articulated. For example, passage of national environmental legislation that would impose new regulations on existing power plants could have a multitude of effects on both the existing power system as well as system expansion options. New constraints on dispatch will make the power system less flexible. The capital costs associated with retrofitting existing plants with required pollution controls may encourage state regulators to require that such investments compete with new supply in future power auctions. Social policy considerations can only complicate the design and implementation of bid evaluation systems.

It is in the interest of utilities, regulators, and private suppliers to develop bidding systems that are efficient, workable, and fair. In order to achieve these objectives, it will be necessary to experiment with and analyze new ideas to determine how much information and risk sharing is appropriate. This task is important because the evolution of the electric power markets will increasingly be determined by bidding procedures and contractual arrangements. The cost of failure could be a major regulatory crisis in the power sector which all parties can ill afford.

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