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DESIGNING PURPA POWER PURCHASE AUCTIONS: THEORY AND PRACTICE

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August 1987

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EXECUTIVE SUMMARY

The Public Utilities Regulatory Act (PURPA) requires there to be procedures for electric utilities to buy electric power from qualifying cogenerators and small power producers (QFs) at rates up to "avoided cost". This has led to price-posting procedures at prices calculated as the utility's marginal cost. Unexpectedly large sales at these prices and slow adjustment to falling energy cost are partially responsible for payments to QFs in excess of the utility's true avoided cost. Using competitive bidding instead of posted prices has been proposed as a way to avoid this outcome. This report reviews bidding theory and explores four issues that arise in designing auction systems for the purchase of power from QFs under PURPA. With the exception of one appendix, it does not consider broader auctions involving non-QF bidders. One of these four issues is the choice of auction format between progressive oral auctions, Dutch oral auctions, standard discriminatory or "first-price" sealed bidding (if you win, you get paid the amount of your bid), and nondiscriminatory or "second-price" sealed bidding (all winning bidders are paid the amount of the best losing bid). Another issue is the extent to which non-price factors influence the auction and the manner in which they do. A third issue is the way in which bid acceptance procedures deal with the discrete quantities of power offered by different bidders. For example, if a utility that needs 500 MW that it can supply at 10¢ per kWh, receives three all-or-nothing bids, one offering 300 MW at 7¢, one offering 250 MW at 8¢ and one offering 200 MW at 9¢, which bids should it accept? The fourth issue is the frequency of auctions. After discussing these issues, the report explores practical details through a case study of a PURPA auction using publicly available data representative of conditions facing Southern California Edison Company.

With respect to auction format, the report recommends sealed procedures over oral ones. It identifies flaws in the arguments in favor of the economic efficiency of nondiscriminatory sealed bidding and recommends familiar discriminatory sealed bidding over the much less common nondiscriminatory format.

In discussing non-price features, we note the tradeoff between simplicity and economic precision. We identify some factors, such as capacity value and transmission access costs, that are relatively amenable to differentiation into components with separate payment streams and performance factors. Others, such as financial risk and dispatchability are not. We also note with approval the approach taken in Massachusetts to deal with financial risk, and we note the difficulty of dealing with dispatchability when it is important.

The discrete nature of bids can cause difficulties. There are many different ways to decide which of a given set of bids to accept. We recommend that bid acceptance rules be spelled out precisely before an auction. The minimum cost selection of bids for meeting a given power requirement may involve accepting a bid with a higher unit cost than a bid that is rejected. It is undesirable for the utility to accept rigidly the discrete nature of the bids and select the set of bids that provides the desired amount of power at the minimum cost. We recommend four measures that a utility can use to reduce the impact of the discrete nature of the bids. These are (1) encouraging multiple bids by a bidder offering incremental quantities, (2) allowing a marginal bidder to downsize the quantity offered if it is too big (given the other lower bids) to be acceptable, (3) allowing a reasonable tolerance in the definition of the required quantity, and (4) valuing excess power beyond the desired quantity at its value to the utility in deciding if a marginal bid is acceptable. With these four measures, we recommend a bid acceptance procedure that considers bids sequentially in order of increasing cost per kWh. Such a procedure will have good economic and bidder incentive properties and will be more stable and "fairer" than a procedure that rigidly minimizes utility cost given the bids.

We recommend that PURPA power purchase auctions be held at least every few years if utility need for capacity allows and that they not be held at much shorter intervals. Too frequent auctions can put large projects at a disadvantage and facilitate collusion. Too infrequent auctions can put at a disadvantage time sensitive potentially attractive projects.

Our Southern California Edison case study is based on cost conditions anticipated by the utility for the mid-1990's. We use the UPLAN model to estimate avoided cost based on methods prescribed by the California Public Utilities Commission. We provide a simple characterization of the "demand curve" for power. Bidders are represented by cost functions approximating the opportunities available to natural gas-fired cogenerators in Southern California.

From the study, we have been able to observe that large-scale projects will cause difficulties in designing bid acceptance procedures, that estimation error can introduce some inefficiency in first price auctions, and that utility costs will exceed social cost minima by 10-20%. Most of these deviations, however, are transfers of economic rent to producers and not economic inefficiency. In particular, economic inefficiencies associated with the use of discriminatory auctions were typically under 0.5%. Furthermore, utilities are likely to pay less for power under auction procedures than using posted prices.

Included with the report are a number of appendices. Some of these present original theoretical derivations. One calculates the effect of revealed second-price auctions in models with subsequent negotiations in which part of the revealed economic rent is captured. Another calculates the optimal selection of quantity to bid when a bid is both a price and a quantity. One appendix presents a workable mathematical procedure for selecting the lowest cost set of bids to a utility. Another presents a precise specification of a sequential bid acceptance procedure and an example of its application. One large appendix contains an extensive discussion of additional issues that would arise if an attempt were made to deregulate all new power generation capacity by removing the technology restrictions (i.e. small power or cogeneration) on bidders in PURPA power supply auctions. The final appendix illustrates how the interaction of bidders' capacity and bid price decisions can reduce the economic efficiency of discriminatory auctions.

I. INTRODUCTION

1.1 The PURPA Power Purchase Problem

Under the Public Utilities Regulatory Policies Act (PURPA), state regulatory commissions are required to establish procedures under which electric power, produced by Qualifying Facilities (QFs), would be purchased by electric utility companies. Typically, the procedures established have allowed QFs to obtain long-term contracts to sell power to the utilities at a fixed price or a price tied to the costs of fuels used to generate power. The contracted prices were to be set to represent the utilities' avoided costs when QF power is substituted for the power that the utilities would otherwise have generated themselves or purchased elsewhere.

Recently, the availability of PURPA contracts to sell power to utilities has created, in some areas, an oversupply of power from QFs. There were two reasons for the oversupply. First, the regulatory formulas setting prices for QF power were insufficiently responsive to decreases in fossil fuel prices. Consequently, lowered expectations concerning fuel prices created a large influx of QF power offerings starting in 1984. Second, the utilities' (marginal) avoided costs fall as more power is obtained from QFs. Consequently, the avoided cost estimates used to set PURPA contract prices have proved excessive, in light of the large amount of QF power that has been offered to the utilities. These shortcomings are discussed in a DOE report prepared by Pfeffer, Lindsay & Associates [1986].

The existing PURPA power contracting system can be characterized as a "price posting" procedure—a price for offerings of PURPA power is announced, and the utility is then obligated to take all the power it is offered at that price. An alternative system could be based on a procedure of announcing the quantity of PURPA power from new capacity that a utility expects to use in the future, and then accepting bids from QFs to supply this quantity. Under this bidding system, the quantity of power obtained from QFs would be controlled directly, while the price of the power obtained would be set by the bidding procedure.

1.2 This Report

There are many ways to conduct auctions. Different auction designs can lead to very different results. This report explores the design of auctions for the purchase power from QFs under the PURPA, making recommendations where justified and identifying relevant factors and their effects when the design choices are difficult. While it appears that a well designed auction can eliminate some abuses of the posted price system, it is not the primary purpose of this report to argue that auctions are superior to posted price systems. Nor, with the exception of the brief discussion in the following subsection, do we consider negotiations an alternative to PURPA auctions. The one substantial diversion in this report from considering the design of auctions for utility purchase of QF power is an appendix that considers the issues that would arise if the technological restriction on QF power were relaxed in order to deregulate all new power generation.

1.2.1 Negotiations and PURPA Auctions

Though there are many variants and combinations, there are basically three different ways of arriving at a selection of QF power suppliers and the price for their supply: posted prices, auctions, and negotiations. By *requiring* utilities to buy PURPA power at or below avoided cost, the PURPA effectively eliminates the utilities' right to say no and therefore their ability to negotiate. It is beyond the scope of this report to review the reasons that led to that decision or to review its current appropriateness. However, electricity production is so complicated that a formal selection process is unlikely to set perfect terms for it. Hence, post-selection negotiations between a successful QF bidder and the utility are likely to be desirable. In considering auction design issues, we have kept in mind that such negotiations are likely to occur and that participants in the auction process are likely to anticipate them.

Another issue that arises in discussion of bidding for the right to supply QF power is the possibility of combining bidding and negotiations. They might be combined in a number of different ways. One possibility, for example, is that bids would be used to select a "short list" of potential suppliers; the utility would then negotiate in a relatively unrestricted way with those on that short list. In our view, this approach effectively restores to the utility the right to refuse and, therefore, the ability to discriminate between potential suppliers for its own purposes (including, possibly, its ownership interest in one or more of the potential suppliers). Such a process is, however, fundamentally a negotiation of the kind that the PURPA was intended to eliminate, so we do not attempt to analyze it further or to consider other similar schemes here.

Another very different possibility is that bidders could modify their initial bids in a way that is generally understood before the bids are made. In a sense, this too is a negotiation, but it is prestructured. We consider such prestructured bid modification processes and recommend one.

Finally, it is important to mention the role of negotiations, subsequent to an auction, between successful bidders and third parties such as permitting authorities, construction firms, financial institutions, and labor unions. Such negotiations are highly likely. We have considered the effect of such subsequent third-party negotiations on the choice of auction format, and, as we describe below and in a technical appendix, we have found them to have significant implications which have apparently not been dealt with previously in auction theory.

1.2.2 Report Organization

The introduction to this report continues with an extensive survey of the literature relevant to the PURPA auction design issue. The following section of the report examines potential criteria for designing PURPA auctions and then examines several particular auction design issues. These include the auction format (e.g., oral progressive auction, "Dutch" oral auction, discriminatory sealed bids, and nondiscriminatory sealed bids), the factors to take account in evaluating bids, dealing with possible mismatches between the discrete quantities of power offered by low bidders and the quantity needed by the utility, and the frequency of auctions. Section III of the report presents case study of the application of an auction system to a situation presented by public data on Southern California Edison. The main body of the report ends with a brief conclusion.

In addition to the appendices already mentioned, the report contains several others that present technical derivations or provide details for the case study.

1.3 Bidding Theory

This section reviews of the extensive literature on competitive bidding. (Surveys of this literature have been written by Engelbrecht-Wiggans [1980] and by McAfee and McMillan [1987], and Stark and Rothkopf [1979] published a bibliography of almost 500 items).

Our literature review helps us find theories useful for analyzing the PURPA problem.

The bidding theory literature can be divided into decision theoretic and game theoretic categories. The former examine the optimal strategy of a single bidder; the latter are concerned with describing auctions in equilibrium, i.e., in which each bidder follows a strategy that is optimal with respect to his competitors' strategies. The basic ideas in the decision theory literature are discussed in the case study in Section III below in the context of developing strategy functions for individual bidders. (Key theoretical papers in that literature are by Friedman [1956], Capen, Clapp and Campbell [1971], and Oren and Williams [1975]. While no great difficulty is involved, apparently no theoretical paper in this literature discusses the simultaneous determination of the optimal quantity and price to offer, so we have included a theoretical deviation of this kind in Appendix D.)

The rest of this section reviews the game theoretic literature.

Most of the bidding literature is concerned with the situation in which the bid taker is the seller of the item ("high-bid-wins"). In many cases, however, the bidder may be a seller ("low-bid-wins"). This would be the case for the PURPA power auction, for instance.

In considering theoretical bidding model results, it is usually not important whether the auction is a high-bid-wins auction or a low-bid-wins auction, since in most respects these auctions are mirror images of each other, and any result for one of them will have an analogous result for the other. Since the PURPA power auction would be a low-bid-wins auction, our discussions of it will reflect this. On the other hand, most results from the bidding literature are expressed in terms of a high-bid-wins context, and it is convenient to present results from the literature in this form.

1.3.1 Bidding Model Common Assumptions

Almost all theoretical analyses of bidding equilibria share the following assumptions about the nature of bidding:

- Each bidder behaves rationally and expects his competitors to also behave rationally.
- Competitors share a common view of the information available to them and of the rules of the auction.

In any real world context, of course, one or both of these assumptions may be violated, particularly if the auction situation under consideration is a new one, with which the bidders have had little experience. See Rothkopf [1983a and 1983b] for a discussion of reasons for apparent non-rational behavior by bidders.

In addition, most theoretical bidding analyses make the three assumptions discussed next. (The effect of relaxing these assumptions is examined in more detail in section 1.3.4 below).

- The number of bidders is fixed and known to the bidders.

In fact, the number of bidders participating in an auction may be influenced by the nature of the auction itself, including the auction rules (discussed below). For example, there will often be pre-bidding expenses borne by bidders, in order to prepare themselves for the actual auction. Since, in the long run, these costs must be recovered from bidders' profits earned in the auction, the extent of these costs will affect the number of bidders. (For an analysis of these issues, as they arise in the Federal oil and gas lease auctions, see Gaskins and Teisberg [1976]). Consequently, the number of bidders and the return to the seller may depend upon the extent to which any particular auction form creates incentives for bidders to incur bid preparation costs.

Most theoretical bidding models also assume:

- The auction is a one-time event that can be analyzed in isolation from subsequent or earlier events.

The one-time event assumption needs to be modified to take account of effects on cost and competitive behavior. The cost effects may be accounted for, in principle, by estimating in a cost calculation the opportunity value in future auctions of physical and organizational assets. For example, a bidder on a construction project has to consider that he may lose future opportunities for projects by tying up his crew and equipment on the current project. Taking account of cost effects has been discussed in the literature dealing with bid optimization by a single bidder by Kortanek, et al. [1973]. The competitive effects of sequential auctions have been dealt with by Oren and Rothkopf [1975]. Using a reaction function approach, they found that bidders would bid less aggressively as the time between auctions decreased, as the discount rate decreased, and as the assumed future reaction by competitors to aggressive bidding increased. To the extent that PURPA auctions involve repeated sales (over time) of a number of power contracts in each sale, the majority of theoretical results should be understood as suggestive only, for the PURPA bidding problem.

Finally, most theoretical analyses of bidding assume:

- There is no collusion among bidders.

While there is no particular reason to expect collusion in the PURPA power bidding context, it is nevertheless appropriate to note that there are relatively few QF suppliers, they tend to belong to a few trade associations, and the stakes are high. Thus, it is also appropriate to be aware of the no-collusion assumption in considering theoretical results from the literature. In particular, there is evidence from other auction contexts an auction system's resistance to forms of cheating (rather than optimality in a model without cheating) has determined the choice of auction system.

1.3.2 Bidding Model Classes

While the assumptions above are common to most bidding models, the next assumptions separate theoretical models into a variety of classes. The first of these assumptions concerns the number of items for sale in the auction:

(1) Item(s) for Sale (or Purchase)

(a) Single item,

(b) Multiple items.

A large part of the theoretical literature on bidding deals with the problem of selling a single item through a bidding process. Since the PURPA bidding situation involves selling a number of power sales contracts (or, perhaps more appropriately, power sales options) in a single auction, the theoretical literature on the sale of multiple items in a single auction is more directly applicable to the PURPA bidding problem.

The second assumption concerns the value of the item (or items) and the information available to the bidders about this value:

(2) Values and Information

(a) Symmetric independent private values,

(b) Asymmetric independent private values,

(c) Symmetric common value,

(d) Asymmetric common value.

In an independent private values model, the expected value of the item to each bidder is exactly and certainly known to that bidder. At the same time, however, the value of the item to each other bidder is not known to any one bidder, and instead is taken to be an independent random drawing from a known probability distribution. If this probability distribution is the same for all bidders, the model is referred to as a symmetric model; while if this probability distribution is different for one or more bidders, the model is an asymmetric model. The independent private values model is presumably most appropriate for auctions of items desired by bidders for their personal use, e.g., an auction of antiques to antique collectors.

The alternative to the independent private values assumption is the common value assumption. Here, the value of the item for sale is the same for all bidders, but it is not known to any of them. Instead, each bidder typically has some information, represented as a random observation from a probability distribution which depends on the unknown true value. Again, if the probability distribution from which the bidders' information is drawn is the same for all bidders, the model is a symmetric model; while if the distribution is different for at least one bidder, the model is an asymmetric model. The common value model is most appropriate as a representation for auctions of mineral rights. Since mineral rights presumably will yield approximately the same future net revenue stream to whichever bidder wins, the value of the rights must be approximately the same to each bidder, even though it may be quite uncertain to all of them.

The PURPA power auction appears to combine some characteristics of both the independent private values model and the common value model. The PURPA auction is like the common value model to the extent that bidders intend to use the same technology to produce their power, and there is uncertainty about the costs of this technology. On the other hand, to the extent that bidders are intending to use different technologies and there is little uncertainty for a bidder about the cost of its own technology, the PURPA situation is like the independent private values model.

To the extent that the PURPA auction is like the common value model, it may be like a symmetric version of that model. That is, all bidders are assumed to have approximately the same quality of information about the cost of the common technology to be used to supply the power. On the other hand, to the extent that the PURPA auction is like the independent private values model, it is most reasonably treated as an asymmetric version of this model, because the value of the contract to each bidder is driven by the technology which that bidder intends to use to supply power. Since these technologies differ among bidders, there is no reason to think that in the independent private values formulation of the problem, each bidder would assume all other bidders' contract values were drawn from the same probability distribution.

The third assumption concerns the risk aversion of the bidders:

(3) Risk Aversion

(a) Bidders are not risk averse, or only risk averse in placing a value on the item, if they owned it,

(b) Bidders are risk averse with respect to the outcome of the auction.

The most common assumption is that bidders are risk neutral. When bidders are assumed to be risk averse with respect to the outcome of the auction, this specification of the bidding problem seems to be inconsistent with common intuition about what it means to be risk averse. When we speak of someone being risk averse, we normally mean that he or she is cautious. In this sense, a risk averse bidder will be one who bids cautiously in case the asset won is worth less than anticipated or the contract won is unexpectedly expensive to execute. However, the application of the classical risk-utility theory of von

Neumann and Morgenstern to auctions—especially in an independent private values contest—focuses on the risk of losing the auction.. Thus, in this context a "risk averse" bidder bids more aggressively than a "risk neutral" one. For the most part, we will not put a lot of weight here on the bidding models that incorporate bidders' risk aversion.

The last assumption concerns the rules of the auction:

(4) Auction Rules

(a) First-price sealed bid

(b) Dutch

(c) English

(d) Second-price sealed bid.

The first-price sealed bid auction is common sealed bidding in which all bidders submit a single bid in a sealed envelope (or some other private communication). When the bids are opened, the winning bidder is the one with the highest bid, and this bidder obtains the item by paying the seller the amount of his bid. If there are to be multiple winners, the auction is "discriminatory." With K winners, the K highest bids win, and each winner pays the amount of his own bid.

In the Dutch auction, prices are called out (or otherwise made public), starting at a very high price at which no bidder would be willing to purchase the item. Then, progressively lower prices are called out until one of the bidders indicates his willingness to pay the last price named. This bidder is the winner, and he obtains the item by paying the last named price to the seller. If there are multiple items for sale, this first bidder takes as many as he wishes at its price. If there are any items left, the auction resumes with the calling of successively lower price.

The English auction is also known as an open or progressive auction. This is the standard kind of auction in which bidders indicate to an auctioneer that they will top the current best offer by a certain (usually small) amount. Once the price reaches the point where no one is willing to top the last price bid, the bidder submitting the last bid is the winner, and he obtains the item for sale by paying the last bid price to the seller. Note that the winning bidder need pay only marginally more than any other bidder is willing to pay no matter how much he would be willing to bid.

Finally, the second-price sealed bid auction is one in which all bidders submit a single bid in a sealed envelope (or some other private communication). The bidder submitting the highest price is then the winner, and he obtains the item by paying the amount of the second highest bid to the seller. If there are multiple identical items for sale, "second-price" becomes "highest-losing-price."

Taken together, assumptions (1), (2), (3), and (4) above create the logical possibility of 64 distinct types of bidding models (or even more, if the possibility of part independent private values, and part common value is admitted). Therefore, we will not attempt to present results exhaustively for each of these bidding model types. Instead, we will concentrate on the results which are most prominent in the literature, and those which have special significance for the PURPA bidding problem.

1.3.3 Prominent Bidding Results

1.3.3.1 Under Basic Assumption

A number of important results in the literature have to do with the way that the four auction rules mentioned above affect the behavior of bidders and the performance of the auction. The bulk of this theory is developed around the following assumptions:

(1a) Single item

(2a) Symmetric independent private values

(3a) Risk neutral bidders.

(For the seminal work on this model, which contains most of the results cited below, see Vickrey [1961]). For this kind of model, the first-price sealed bid and Dutch auction rules are "strategically equivalent." This means that the optimal bidding strategy for each (non-colluding) bidder in the auction is the same under either auction rule. Consequently, the winning bidder will be the same as the revenue to the seller, under either auction rule.

In simple terms, the optimal bidding strategy in a first-price sealed bid or Dutch auction is as follows. Any given bidder determines the probability distribution of the second highest bid for the item, assuming that the given bidder himself places the highest value on the item. Then, the given bidder submits a sealed bid (or stops the auction process in the Dutch auction) at the price that represents an optimal trade-off between a lower probability of winning, on the one hand, and a higher profit if he does win, on the other hand. It turns out that in equilibrium, the bidder who wins this auction submits a bid equal to the expected value of the second highest valuation.

In addition, for the model with the above assumptions, the English and second-price sealed bid auctions are also strategically equivalent. In the English auction, each bidder stays in the competition until the bid called by the auctioneer exceeds his valuation. At that point, he drops out. The auction is over once the second highest valuation is reached. Although less intuitively obvious, the optimal strategy for bidders in the second-price sealed bid auction is to submit bids equal to their own valuations. Then, the winning bidder pays the amount of the second highest bid, which is exactly the same as what this bidder would have paid in an English auction. Consequently, the revenue to the seller is the same under the English and second-price sealed bid auction rules.

Because the optimal strategy of each bidder in the second-price sealed bid auction is to bid exactly his own valuation of the item being auctioned, this auction rule is said to lead to "truth revealing" behavior. Second-price auctions are "truth revealing," because they "disconnect" the price a winning bidder pays from the decision to award the item to that bidder. To understand this, consider the situation faced by bidders in a PURPA auction of a single power contract.

For any given bidder in the auction, consider the alternatives of bidding more or bidding less than that bidder's true cost of power production (true cost of production here is meant to include normal cost of capital, appropriately adjusted for the risk of the investment). Since the bidder does not know whether or not he will be successful bidding his true cost of power, he must consider both situations.

First, suppose the bidder would be successful, bidding his true cost of production. If he lowers his bid from this level, he will still be successful and he will still be paid the same price for power—so there is no advantage in lowering his bid. If he raises his bid, the amount he is paid (if successful) will still be same, but he starts to run a risk of becoming an unsuccessful bidder—so there is a disadvantage in raising his bid.

Second, suppose the bidder would be unsuccessful, bidding his true cost of production. If he lowers his bid from this level, he may become a successful bidder. However, if he does become a successful bidder, it will only be because his bid is less than another bid that was below his previous bid (i.e., his cost of production). If this happens, the bidder will be successful, but the price he will be paid will be less than his cost of production. Consequently, there is a disadvantage in lowering his bid in this situation. On the other hand, if the bidder would be unsuccessful bidding his true cost of production, he will still be unsuccessful if he raises his bid from this level—so there is no advantage to raising his bid.

In sum, raising or lowering the bid from true cost of production will either be disadvantageous to the bidder, or it will have no effect on the bidder. Consequently, the best strategy for the bidder to follow is to bid his true cost of production. Note also that this is true regardless of the bidding strategies being followed by other bidders.

Either the second-price sealed bid auction or the English auction is guaranteed to sell the item being auctioned to the bidder who values it most. This is an efficient outcome. It is also true that the first-price sealed bid and Dutch auctions will result in the item being sold to the bidder who values it most highly. (Note, however, that this result is true only under the symmetry assumption—see below for more on this.)

The final result for auctions that conform to the assumptions listed above is that all four auction rules return the same expected revenue to the seller of the item. While this result is quite surprising at first, it is less so in light of the result cited above concerning the optimal strategy of a bidder in the first-price and Dutch auctions. Recall that this strategy is to submit a sealed bid equal to the expected second highest valuation, on the assumption that the bidder is himself the highest evaluator of the item. This implies that the expected value of the winning bidder's bid will be the expected value of the second highest valuation. Since this is exactly the expected value of the winning bidder's payment in the second-price and English auctions, the revenue equivalence of all four auctions is apparent. (For a very general mathematical proof, see Myerson [1981]).

It is useful to discuss revenue equivalence further and in the context of an auction in which there are many bidders, each with one item to sell at a different cost, and a single buyer who desires many items (but fewer than there are bidders). If the auction is nondiscriminatory, the optimum strategy for each bidder is to bid at his cost. This results in a supply demand situation as shown in Figure 1.1a. If, on the other hand, the auction is a discriminatory auction, then each bidder will adjust his bid (as dictated by decision theory) so as to just balance the potential extra profit from bidding higher with the potential loss of all profit from bidding above the cutoff value. If all the bidders were to estimate a high cutoff value relative to the economic equilibrium, then the actual cutoff value would, in fact, be high relative to the equilibrium although lower than the bidders estimated; bidders would tend to get higher than equilibrium profits. If all the bidders were to estimate that the cutoff value would be low relative to economic equilibrium, then the value would, in fact, be low (but higher than the bidders estimated), and bidders would tend to get lower than equilibrium profits. If, however, bidders tend to estimate a cutoff value that is approximately at the economic equilibrium value, then the bids will follow approximately the pattern shown in Figure 1.1b. In this figure, the two shaded areas are equal, which implies equivalent revenues.

With consistent expectations, the top price paid in a discriminatory auction will exceed the uniform price paid in a nondiscriminatory auction, and the lowest price paid will be less. Revenue equivalence means that the average price will be the same. Relative to the nondiscriminatory auction profits, profits for bidders whose costs are low will tend to be smaller and profits for winning high cost bidders will tend to be larger. The more accurately the bidders can forecast the cutoff price, the smaller these differences will be.

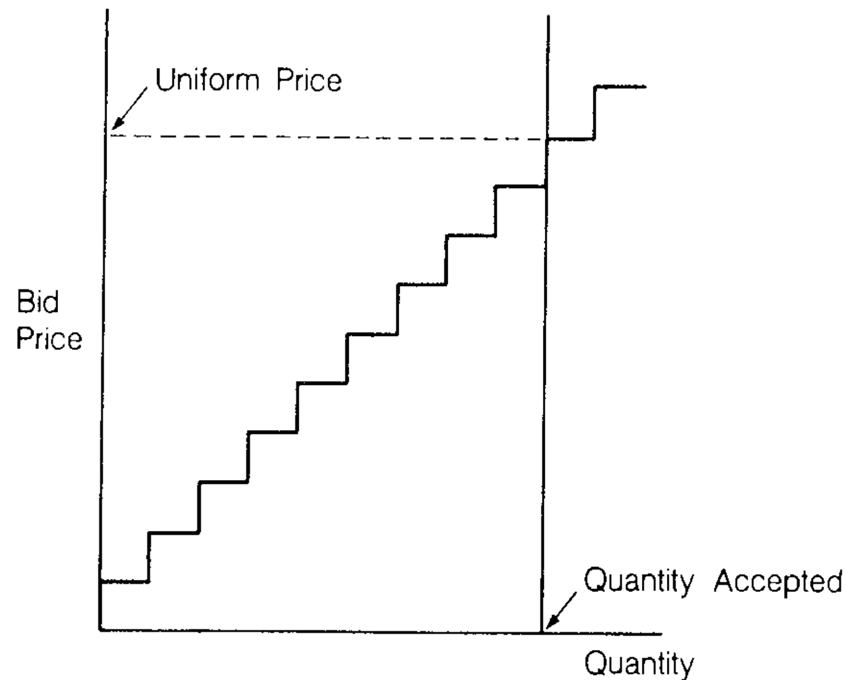

Figure 1.1a Second Price Auction

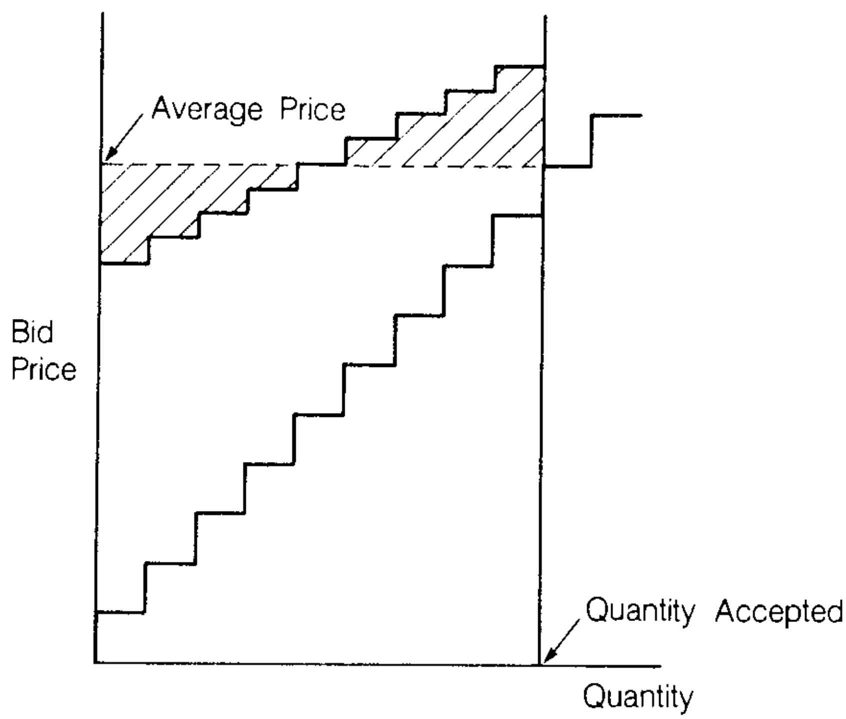

Figure 1.1b. First Price Auction
With Consistent Expectations

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1.3.3.2 Variation of Basic Assumptions

Next, we turn to the implications of different types of bidding models. First consider changing the symmetry assumption, i.e. the new assumption is

(2b) Asymmetric independent private values.

Under the second-price sealed bid (or English) auction rule, it remains optimal for each bidder to bid his true valuation of the item (or remain in the competition until the current bid exceeds his own evaluation). Thus, these auctions reveal truth, and they result in the item being awarded to the bidder who values it most highly, when the symmetry assumption is given up.

For the first-price sealed bid and Dutch auctions, however, the situation changes when symmetry is given up. To understand this, first suppose that there are only two bidders, and that, by chance, they happen to "draw" the same valuation of the item. Because these valuations are drawn from different distributions (and the bidders both understand this), each of the two bidders will assess a different distribution for the competitive bid, and hence, each will submit a different bid, even though their valuations are the same. Next consider increasing the valuation of the bidder who bids low. Increasing this valuation will cause this bidder to bid more, but since his bid started out as the lower bid, it will usually be possible to increase his valuation at least a little bit, without causing him to become the higher bidder. Thus, it is possible to have a situation where this bidder actually has a higher valuation, but submits a lower bid.

This kind of outcome is certainly inefficient, and gives revenue to the seller that is different from what the seller would receive under a second-price or English auction. In general, the seller's revenue could be higher or lower than it is under the second-price or English auction rules. See McAfee and McMillan [1987, pp. 713-714].

To some extent, the possibility of inefficiency in the first-price auction depends upon the ease of transferring PURPA power contracts after the auction has been concluded. If it is easy to transfer such contracts, then any misallocation of contracts in the initial auction is theoretically correctable after the auction, through privately negotiated deals between possible PURPA power suppliers. Whether such deals would or should be allowed is a separate question. However even if they are allowed, whether they would actually take place, is uncertain. Information that a deal is mutually advantageous to the deal makers may not be available, and even if it were, transaction costs might be large enough to eliminate any potential gains from making a deal.

Next we change the perspective to consider another major class of bidding models, characterized by the values and information assumption:

(2c) Symmetric common value.

As indicated above, a PURPA power auction could have something of the character of a common value model if many or all bidders were intending to use the same technology to produce power, but each one of them has independent information about the true cost of power produced by that technology.

It is in the symmetric common value context that the idea of the "winner's curse" arises. This is the observation that if two or more bidders each independently estimate the (common) true value of an item being auctioned, then the bidder who places the highest value on the item is statistically likely to have overvalued it. This is true even though each bidder's value estimate, taken by itself, is an unbiased estimate of the value of the item. In symmetric common value models, of course, the bidders are fully aware of the "winner's curse," and they bid less than their estimates of value, in order to avoid winning the auction with a bid that is too high.

Most of the models incorporating the symmetric common value assumption also assume that the auction form is the first-price sealed bid rule. In this context, one standard result is that the expected price to the seller increases as the number of bidders increases, that the expected price converges to the true (common) value, as the number of bidders becomes arbitrarily large (Wilson [1977]). A second standard result is that the expected price to the seller increases as the uncertainty in bidders' value estimates decreases. This is clear in the limiting case where bidders have no uncertainty in their estimates — the equilibrium strategy is then for each bidder to bid exactly the known true value, in which case the seller obtains the true value, regardless of the number of bidders in the auction.

Some more recent work has revealed interesting differences in the performance of the alternative auction rules (Milgrom and Weber [1982]). As in the independent private values model, the first-price sealed bid and Dutch auctions are strategically equivalent in the common value model. That is, the bidders' optimal strategies and the seller's expected revenue are the same in both auctions.

However, the second-price sealed bid and English auctions may no longer be strategically equivalent to each other in the common value model if during the English auction process information is revealed about each bidder's estimate of the common value. Information is revealed to the extent that bidders can determine when their competitors drop out of the bidding. This information can be used by the bidder who ultimately wins the auction to improve his own estimate of the true (common) value of the item being sold. The result is that the English auction form may return, on the average, more revenue to the seller than the second-price sealed bid auction, under the common value assumption.

Moreover, the second-price sealed bid auction returns more revenue that the first-price or Dutch auction. Thus, there is a ranking of auction forms, in terms of the seller's expected revenue, in the common value model. From highest to lowest, the ranking is English, second-price sealed bid, first-price sealed bid and Dutch (tie).

There is another interesting theoretical result for the common value model. This is that information available to the seller about the true value of the item being auctioned should generally be fully and honestly reported to the bidders before the auction (Milgrom and Weber [1982]). This result occurs because with equilibrium bidding the seller's revenue goes up as bidders' uncertainty goes down. However, Kagel and Levin [1986] found persistent disequilibrium behavior in experimental common value auctions. With the behavior they observed, bidtakers would be better off not reducing bidder uncertainty.

Next, we turn to the symmetric independent private values assumption, and consider the class of models in which there is more than one item being auctioned; i.e., the new assumption is:

(1b) Multiple items.

Since two or more contracts would most likely be awarded in a PURPA power auction, this change of assumption is particularly relevant.

The major implication of selling multiple items in the same auction is that the truth revealing property of a second-price or English auction may be lost, together with the assurance that the items will be awarded to those who value them most highly. To see why the truth revealing property may be lost with multiple bids, consider a hypothetical second-price auction of PURPA power contracts. In such an auction, with the possibility of multiple contract awards, the winning bidders would receive a price equal to the amount of the lowest unsuccessful bid. Suppose, for example, that there are bids at 2.5, 3.1, and 3.3 cents. Suppose, further, that the two lower bids are large enough to satisfy the power requirement of the utility. Then, the second-price procedure applied in the multiple bid context requires that both of the successful bidders (who bid 2.5 cents and 3.1 cents) would receive contracts to sell power at 3.3 cents per kWh.

If it happens that the bidders submitting all three bids are different, then the truth revealing property of second-price auctions persists. This is because the price received is not connected to the price bid. However, if one or more of the bidders submits more than one bid, the situation changes: suppose that the same bidder has submitted the 2.5-cent bid and the 3.3-cent bid. If we again consider the incentives for this bidder to raise or lower his bid from true cost, it is apparent that such incentives now exist. Specifically, if the 3.3-cent bid is raised, the profit earned on the 2.5-cent bid will be increased. In general, any higher bid submitted by one bidder will affect the profitability of all of that bidder's lower bids.

As observed by Dubey and Shubik [1980], the disconnection between the bid and the price paid can be recovered in the multiple bid case, by employing the following procedure. For each bidder, the price paid is determined by the highest losing bid, calculated as if none of the bidder's higher bids had been submitted. Extending the example given earlier, assume that there is a fourth bid at 3.5 cents, which was submitted by an entirely different bidder. Then, the bidder bidding 2.5 and 3.3 cents would receive a price of 3.5 cents for the successful bid at 2.5 cents. The successful bidder at 3.1 cents would continue to receive a price of 3.3 cents.

By preserving the disconnection between bid(s) submitted and price paid, the above procedure preserves the truth revealing property of a second-price auction, even in the face of multiple bids by a single bidder. This approach, however, has distinct disadvantages. While it may reveal the bidders' valuations, it is clear, that the utility's average cost of power goes up, as more bids are submitted by each bidder, holding everything else constant.

Also, it is clear that bidders submitting more bids may be paid a higher average price on a successful bid than is paid to another bidder with an identical successful bid, but no other bids in the auction. This is an explicit acknowledgment of market power. It may create at least an appearance of unfairness. While one aspect of this unfairness could be corrected by paying all successful bidders the highest price determined for any one bidder under the procedure described above, doing so would further increase the utility's costs of obtaining power in the auction. It would also destroy the truth revealing incentives for bidders.

Finally, we return to the single item, symmetric, independent, private values model, but consider bidders to be risk averse in the classical sense of von Neumann and Morgenstern.

(3b) Risk Averse Bidders

If PURPA bidders are risk averse in the sense that they are concerned about the risk of losing the auction, then bidding theory indicates that with equilibrium bidding strategies the utility will do relatively better with a first-price auction (sealed bid or Dutch oral) than with a second-price auction (sealed or English). (See McAfee and McMillan [1987, p. 719] and their references, including Riley and Samuelson [1981]). In effect, bidders concerned about the risk of losing the auction will tend to bid lower, sharing more of their cost advantage with the utility in order to lessen that risk. There are no equivalent formal results for correlated value auctions, but intuition suggests that as the correlation of values increases towards a common value, the risks associated with winning the auction become important and compete with the risks of losing it, thus reducing or reversing this result.

1.3.4 Relaxing Common Assumptions

This section examines the implications of changing a few of the common assumptions that underlie most of theoretical bidding work. First, if the common assumption,

- The auction is a one-time event that can be analyzed in isolation from subsequent events,

is relaxed, the truth revealing property of second-price auctions may be lost because the information revealed in a second-price auction may damage the competitive position of the bidders after the auction is over. For example, if PURPA power auctions are relatively frequent and dissemination of cost information increases the number of future competitors using the best technology, the bidder who pioneered the best technology will see his profits in future auctions reduced. Alternatively, revelation of cost information could put at a disadvantage a bidder in future situations where the bidder must negotiate with potential business partners, suppliers, labor unions, the bid taker, or government regulatory agencies.

Once the above assumption is relaxed, there would also be differences in the performances of auctions relying on sealed vs oral bidding, because different amounts of information are revealed in the course of these auctions. For example, in a low-bid-wins oral auction, minimum acceptable prices of winning bidders are not revealed. In the PURPA power auction, for example, an auctioneer would call out a decreasing sequence of prices, beginning with avoided cost, until the amount of capacity offered by QF bidders at each price had been reduced to the amount of capacity required by the utility. At this point, the auction procedure would be over, and the minimum price that each winning bidder would have accepted is would not be revealed. By contrast, in a second-price sealed bid auction, the actual bids would make public the minimum acceptable prices of the winning bidders unless there was a successful effort to keep them secret.

Appendix A contains an analysis of the situation where a third party is able to extract some portion of the successful bidder's profit, after a second-price auction. This is an important reality of PURPA auctions not previously dealt with in the auction literature. Successful PURPA bidders must negotiate with third parties for permits, financing construction and labor. Some of these third parties have substantial market power. The analysis in Appendix A indicates that bidders would respond to this situation by bidding more than their true costs, and that the expected revenue to the seller is lowered by the amount of the profit extracted by the third party. This result follows from an application of Myerson's revenue equivalence Theorem [1986] and therefore, like that result, it is quite general. There are three important implications of this analysis. First, in this situation, a second-price auction would no longer be truth revealing. Second, in this situation, the second-price auction would no longer provide as much expected revenue as a first-price auction. The third important implication is that in this situtation second-price auctions are no longer perfectly efficient.

Next we consider the assumption that

- The number of bidders is fixed.

It is clear that the auction outcome can be influenced by the decision of potential bidders to bid and that the form of the auction can influence that decision. Both theoretical arguments and observations of practice support this conclusion. Engelbrecht-Wiggans [1987], critiquing a prestigious paper on optimal reservation prices in auctions, has shown theoretically that the results depend heavily on the assumption that changing the reservation price will not affect the number of bidders. There is also empirical evidence for this from the early history of U.S. commerce.

In the years before the war of 1812, Philadelphia, New York and Boston handled roughly equal volumes of import trade. Much of the imported merchandise was sold at auctions not far from the docks. Shortly after the end of the war, the New York auctioneers, with the express intent of attracting buyers to New York, obtained legislation requiring that all goods offered at auction in New York be sold without reservation (i.e., without withdrawal from sale) to the highest bidder. It worked. Apparently, buyers came to New York to find the bargains, and the ships came to New York to find the buyers. By 1825, when the Erie Canal was ready to open, the port of New York was handling three times the volume of imports handled by either Boston or Philadelphia. All of this is documented in considerable detail in a 1961 history of that port (Albion [1961]).

There is also recent evidence that form of auction matters. The timber industry has consistently lobbied for the use of progressive oral auctions rather than sealed bids for federal timber sales. Regression studies (Weiner [1979]; Hansen [1986]) give results consistent with the government getting more revenue from sealed bids. Apparently, the cause of this deviation from classical revenue neutrality is the reluctance of bidders with distant mills to enter an oral auction for timber near another bidder's mill (see Mead

[1967]). In an oral auction, unlike a sealed bid situation a bidder can react to unexpected competition, thus depriving a bidder with a cost disadvantage of any chance of winning and of any incentive to bid.

The relevant point to PURPA here is not one about optimal reservation prices (avoided cost will be the reservation price in a PURPA auction) or about geographic proximity. Rather it is that the results of the standard "high theory" of auctions use the assumption of a fixed number of bidders and are quite sensitive to it. Any variation in auction rules that tends to attract additional bidders could be of economic importance.

Next we turn to the common assumption

- There is no collusion among bidders.

Some theoretical work indicates the degree to which the alternative auction rules might facilitate collusive agreements among bidders. This work indicates that the greater amount of information generated in an oral auction can facilitate collusion among the bidders (Robinson [1985]). If there is a collusive agreement among bidders, it may be possible in an oral auction to observe whether or not others are sticking to their parts of a pre-arranged bargain. To this extent, the oral auction procedure is more susceptible to collusive behavior than sealed bidding.

For example, assume (1) there are two bidders in a PURPA power auction, (2) either bidder can supply exactly the amount of capacity desired by the utility, (3) Bidder One has a minimum acceptable price of 2.5 cents, while Bidder Two has a minimum acceptable price of 2.6 cents. Suppose, further, that they have agreed to collude, with Bidder One agreeing to make a small payoff to Bidder Two, if Bidder Two will behave as if his minimum acceptable price were 4 cents.

In an oral auction, Bidder One can directly observe whether or not Bidder Two drops out of the bidding at a price of 4 cents, as they had agreed. If Bidder Two does not drop out, Bidder One can respond by remaining in the bidding until the price drops to 2.6 cents, at which Bidder Two will certainly drop out. Naturally, Bidder One would not make the agreed payment to Bidder Two in this case. Consequently, Bidder Two would end up with nothing, while Bidder One would end up with only a 0.1 cent profit on his winning bid. Since this outcome is undesirable from the point of view of both bidders, we would expect that the bidders would in fact be adhere to their collusive agreement.

In a sealed bid auction, however, the result could be different. Suppose, for example, that Bidder Two agrees to bid 4 cents, while Bidder One plans to bid, say, 3.5 cents, in order to avoid a conspicuously large difference between the two bids submitted. Now Bidder Two may be tempted to bid, say, 3.4 cents, hoping to steal the bid from Bidder

One and make a profit of 0.8 cents. Assuming this is in excess of the payoff promised by Bidder One, and assuming that Bidder Two is not worried about the long-term consequences of double crossing his colluding partner, Bidder Two might adopt this strategy in the sealed biding context. Consequently, collusion may be more difficult for bidders to enforce, under a sealed bidding procedure, and this in turn may increase the reluctance of bidders to collude.

II. ANALYSIS OF ISSUES THAT WOULD ARISE IN PURPA AUCTIONS

2.1 Criteria for Designing the Auction

Several auction characteristics are of interest in designing an auction to sell PURPA power contracts: the economic efficiency of the auction; the utility's cost of power obtained through the auction; possible tendencies, if any, of the auction to create and sustain collusive behavior on the part of the bidders; the fairness and appearance of fairness of the auction; and the general workability of the auction design.

2.1.1 Efficiency

A PURPA power auction is economically efficient if QFs with the lowest costs of providing power are the successful bidders. Intuitively, one might expect this outcome from any kind of auction system. However, as indicated in the preceding review of theoretical bidding models, auction inefficiency is certainly possible in some common bidding situations, such as the situation with asymmetric independent private values. And, of course, inefficiency may also result if bidders do not understand the consequences of their bidding behavior in a complicated auction system or if they misjudge the bidding behavior of their competitors. The latter sources of inefficiencies can exist, in any bidding situation.

Although the second-price auction procedure is efficient in some theoretical situations where first-price auctions might not be efficient, the theoretical analyses fail to include two important aspects of the the real world which are important in the PURPA bidding context. Specifically, the truth-revealing property of second-price auctions, which creates the theoretical efficiency of these auctions, is unlikely to be preserved in a PURPA auction. One reason is that there are frequently situations following the auction where it would be disadvantageous to the winning bidders to have fully revealed in the auction their costs of power production. The other reason is that bidders often have different amounts of power to offer at different costs. We, therefore, believe that the theoretical efficiency advantage of second-price auctions is not a compelling reason to favor this auction form over the first-price auction.

2.1.2 Cost of Power

If the lowest cost power producers are the successful bidders in an auction, the cost of power to the utility should be minimized. However, the relationship is not direct, since the cost of power to the utility will depend upon how the benefits (the economic rent) of low-cost power are divided between the power producer and the utility purchasing the power. From a policy perspective, this is a difficult issue. If rent is shifted to the utility purchaser, the ratepayers benefit. However, if the rent is retained by the power producers, the long-run incentive to develop PURPA power is enhanced. Both of these results are usually considered desirable policy objectives.

Most alternative auction forms theoretically provide the same cost of power to the utility. The most compelling exception to this statement is that the progressive oral auction may produce a lower cost of power, to the extent that bidding behavior during the course of the bidding generates information that reduces the uncertainty of the bidders who ultimately win the auction. This theoretical result would carry less weight, to the extent that bidders are quite certain of their costs before entering the auction, or to the extent that other bidders are using different technologies, so the the bidding behavior of any one bidder provides little information to the others. If bidders are averse to the risk of losing the auction, then sealed first-price bidding should produce lower costs.

2.1.3 Risk of Collusion

The existence of incentives for collusion among bidders is generally considered to be undesirable. Collusion would tend to raise the costs of power to utilities, together with the profits of colluding bidders. Also, collusive bidding behavior may create inefficiencies, by setting a price umbrella that encourages entry of new higher cost producers. Finally, of course, collusion is explicitly illegal.

As discussed above, the progressive oral auction is more susceptible to collusive behavior on the part of the bidders. To the extent that collusion is a risk, the expected cost of power to the utility will be higher under an oral progressive auction procedure.

2.1.4 Fairness

Since PURPA auctions would be sanctioned by governmental regulatory agencies, and possibly include regulated electric utilities as sponsors, participants or both, it is important that the auction design be perceived as fair to all participants.

Although theoretical results obtainable under strong assumptions indicate that the cost of power to the utility may be the same under either a first- or second-price auction procedure, the public is likely to think that a second-price procedure is giving something away to the winning bidders. First-price auctions do not usually create such an impression. On the other hand, a case can be made for both the fairness and the appearance of fairness associated with a nondiscriminatory second-price auction which pays all winners the same price.

2.1.5 *Workability*

The costs and practical considerations of carrying out an auction can be affected by auction design. When transactions are small, ease and speed may be prime considerations, some form of oral auction is often used. With PURPA auctions, the amounts involved are large compared to the cost of the auction itself. However, the large amounts involved suggest formal procedures with written bids that can be carefully checked by several different persons in a bidding organization.

Workability can also be a factor in bid acceptance procedures as the discussion below of "lumpiness" will indicate.

2.2 *Overall Auction Format Recommendation*

A principal decision in the design of a PURPA auction system is the choice between sealed first-price, sealed second-price, oral progressive, and oral Dutch procedures. The California PUC, following the sophisticated analysis of Southern California Edison (Vail [1986]; Jurewitz [1986]) has decided to implement a sealed second-price procedure (California PUC [1986]). Other states are moving towards sealed first-price procedures (Massachusetts [1986]), often without explicitly considering other alternatives. We are not aware that any active consideration being given to oral procedures.

Of the four procedures, we recommend the sealed first-price format. Here is our logic.

First, the PURPA auction is a formal procedure involving large amounts of money and simultaneous decisions on multiple bids. This strongly argues for written bid procedures. In particular, the oral Dutch procedure offers no advantages over sealed first-price bidding and can be eliminated from further consideration.

Second, the theoretical arguments for the superior economic efficiency of sealed second-price auctions fail for two reasons: (1) bidders will often have different quantities of electricity to offer at different prices, and (2) bidders often must engage in subsequent negotiations with third parties whose positions may be influenced by the perceived amount of "extra" compensation received by the bidder in a the second-price auction. Each of these factors destroys the incentive of the bidders to bid in a truth revealing manner. Note that these incentive effects are in addition to any purely behavioral reluctance of bidders to engage in the "truth revealing" (i.e., cost revealing) behavior called for by the theory of second-price auctions. It is important to acknowledge, however, that the failure of the argument for the economic superiority of the second-price auction does *not* prove that the first-price auction is more efficient.

The choice on economic efficiency grounds would seem to require a balance between the inefficiency induced in first-price auctions due to the inability of competitors to estimate the cutoff price, and the inefficiencies induced in second-price auctions by bidders' concerns about extra rent capture by third parties and by that rent capture itself. The more regular and important PURPA auctions become, the heavier the latter factors weigh relative to the former as bidders learn to estimate cutoff price more accurately. In addition, in studying the results of the case study described in Section 3 and trying to explain the low inefficiencies we observed, we discovered that the interaction of price uncertainty with design cost decisions can substantially reduce economic inefficiencies due to use of first-price auctions. This result is described in Section 3.5 and further illustrated in Appendix I. Finally, it is not clear to us that either procedure has a relative advantage in dealing with the economic distortions induced by the monopoly power of those bidders able to supply varying amounts of power at different prices.

Having failed to find an advantage for sealed second-price auctions on economic efficiency grounds, we have other reasons for preferring sealed first-price auctions. Such auctions do not raise fairness issues of apparent "overpayment" or explicit recognition of market power. More important, sealed first-price auctions are familiar. They are unlikely to intimidate or scare off potential bidders. Sealed second-price procedures, on the other hand, are almost unknown. Although it is not likely to be a significant problem in the PURPA context, they require an additional level of trust in the bidding process (i.e., trust that the bid taker will not insert a losing bid that lowers the compensation of winning bidders after the sealed bids are opened). Finally, the appropriate strategy for bidding in sealed second-price auctions will be uncertain at least at first.

Finally, we have reconsidered an oral progressive auction format as a potential second-price alternative to sealed formats. Relative to sealed second-price, the oral progressive format has two advantages. It is familiar, and it does not require bidders to reveal how far they would be willing to go. These advantages, however, have offsets. As we have already mentioned, the amounts of money involved in PURPA auctions are very large for oral bidding. In addition, oral progressive auctions are stable under bidder collusion and, therefore, are more subject to it than sealed bids.

On balance, we find nothing superior to familiar sealed first-price bidding.

2.2.1 Multiple Price Bids

As the next section discusses, the commodity offered by the bidders has multiple aspects such as reliability, dispatchability and financial risk. There are auctions in which a single bid offers multiple unit prices for different commodities. This is most common in bidding for construction contracts (See Stark [1974]) but also occurs in federal timber auctions. Such an auction form is typically motivated by the desire of the bid taker to retain the quantity risk. It is notorious that such auctions can be gamed (Stark [1974], GAO [1983]) in ways that lead to undesirable results. Since the common motivation for such auctions is not important in PURPA auctions and since such auctions have difficulties even when that motivation is present, we do not recommend them.

2.3 Bid Evaluation Process

The commodity offered by bidders is complex. It may be desirable to reflect that complexity in the bid evaluation schemes that are used to rank offers. The problem posed by this complexity is that all the relevant dimensions are not easily monetized or reducible to some common measure. Further, as the evaluation scheme becomes more complex, it can become more arbitrary and more subject to gaming by the participants. The tension between simple and complex bid evaluation is illustrated by the contrasting evaluation schemes of the California PUC and the utilities in Massachusetts. In California, the price offered by bidders is the one and only measure of their relative value. The auction design adopted by the California PUC reduces the price issue to a single variable. In Massachusetts, the utilities are proposing complex schemes which involve the balancing of qualitative factors against price.

To elucidate the bid evaluation issue, we first summarize the schemes proposed by Boston Edison (BE) and Western Massachusetts Electric (WEMCO). With this background we then review the various non-price issues that must be dealt with in an auction either through formal evaluation schemes or other procedures. The non-price issues include dispatchability, reliability, financial risks and transmission access.

2.3.1 Summary of Massachusetts Proposals

The Massachusetts Department of Public Utilities (MDPU) adopted an order on August 25, 1986 defining a procedure under which private producers of electricity would submit proposals to sell power to utilities. The MDPU order outlined the general form of the competitive procedure including the factors used to rank different proposals. The utilities submitted Requests for Proposals (RFP) in October 1986. The essential element of the RFP is a scoring system for ranking projects. The two major utilities, BE and WEMCO, took somewhat different approaches. We summarize the formulas proposed by each utility.

The BE formula is the simpler of the two. The bidders' score is computed by the following expressions:

Bidder's Score = Price Component + Quality Component,

where Price Component = Ratepayer Benefit * Risk Breakeven Factor
* Risk Mitigation Factor,

and Quality Component = (Present Value Avoided Cost)/
(Present Value Quality Adjusted Bid)

The Price Component is straightforward. Ratepayer Benefit is the ratio of present value avoided cost to present value of the bid. The two other terms address the risks associated with a bid stream that is "front-loaded." Bidders may need revenue above avoided cost in the early years of their projects. Bids of this kind are allowed, but they impose risks on ratepayers. The Breakeven Factor adjusts for time required for ratepayer benefits to become positive (i.e. present value of bid costs are less than present value of avoided cost). The Mitigation Factor adjusts for the kind of security bidders offer to the utility as insurance against the risk of front loading.

The Quality Component is designed to address less concrete issues. It has two parts. One is a "Development Score" which measures how well-developed the bidder's project is. The second part is a set of Bonus Points. Projects obtain these points if they exhibit features that BE deems desirable. The greatest value is assigned to projects which are not oil or gas-fired (this fuel diversity quality is given three points). The next most important qualities (two points) are dispatchability, maintenance scheduling by BE, favorable site in the transmission and distribution network, and previous development experience. Finally a number of other qualities are assigned a single bonus point. The project score is averaged over all qualities. Both the Development Score and the Bonus Points are used to compute a quality adjusted price. This adjusted price determines the Quality Component of the score.

WEMCO developed a scoring process that can be expressed by the following formulas:

Bidder's Score = (Expected Ratepayer Impact)/
(Confidence Factor * System Compatibility),

where Expected Rate Impact = Sum of Probability(i)* Rate(i) Scenario Impact,

Rate(i) Scenario Impact = (Price Factor (i))/Front-Loading Factor (i);

Confidence Factor = Operating Risk Factor * Development Risk Factor;
and System Compatibility = Weighted Average of Attributes.

The Expected Rate Impact is a probability weighted average of rate impacts in a high, a medium and a low avoided cost scenario. The rate impact in a given scenario is a ratio of the Price Factor (which is the same quantity as the BE Ratepayer Benefit) and a Front Loading Factor. WEMCO's measurement of the front loading effect differs from BE's by concentrating only on the first five years of operation. The Confidence Factor consists of two components called Operating Risk Factor and Development Risk Factor. The Operating Risk Factor is addressed to the potential default of the project. One of its components is a function of the security deposit posted by the developer against cumulative front loading. Its other component depends on estimates of the project's ability to cover its costs with its own projected revenues. For this computation, the developer must supply cost and revenue data that is normally confidential. The Development Risk Factor is a more complicated version of the BE Development Score. Finally, the System Compatibility Factor is similar to the Bonus Points used by BE to weight attributes of projects such as dispatchability, fuel availability, location, project size, and voltage impacts.

This outline of the BE and WEMCO RFPs does not reflect all the details of their scoring processes. It does, however, illustrate some of the pitfalls and promises of complicated scoring systems. The pitfalls are a certain degree of arbitrariness and duplication. In complex formulas such as these, relatively firm economic relations get traded off against qualitative features. The "exchange rate" between the economics and the features is not grounded in anything explicit. WEMCO's formulas seem to involve some double counting. Front loading is treated both in the Ratepayer Impact and the Operating Risk Factor. On the positive side, the explicit treatment of various avoided cost scenarios in the WEMCO formula gives a better picture of the bid economics than using a single scenario.

The sections that follow consider several of the important non-price features which might be considered in evaluating a bid. We discuss the merits of incorporating these into an evaluation scheme and into methods for assessing their relative importance.

2.3.2 Dispatchability

A private producer must choose whether or not to allow the utility control over the project's output. The producer's choice is influenced by both technological constraints and economic values. On the utility's side, the ability to dispatch a project has greater or less value depending on the supply and demand balance and the degree to which system constraints are binding. Indeed, the amount of control implied by the term dispatchability differs qualitatively. At the lower limit of control is the ability to interrupt or curtail briefly during low load hours. At the opposite extreme is total utility discretion. The Massachusetts utilities do not place much value on dispatchability in their scoring systems. It is treated as one among many qualitative features, and not the most important of those. In California, however, dispatchability has much greater value, particularly in Northern California because of the large but variable amount of hydro energy available. Furthermore, existing QFs which cannot be curtailed have limited the utility's ability to purchase inexpensive power from the Pacific Northwest.

Recent regulatory decisions in California regarding the siting of large private cogeneration projects show an increasing emphasis on dispatchability. This has been a response to the perception of a potentially excessive amount of baseload capacity that would have to be purchased under the PURPA regulations. By shifting resources from the baseload to the dispatchable category, the utility is able to purchase larger quantities of low-cost energy from other sources. The terms of the resulting dispatchable purchase contracts vary substantially from project to project and across utilities. The Gilroy Cogeneration Project is a 120-MW facility which will be fully dispatchable by Pacific Gas and Electric (PG&E) during the first four months of each year and completely curtailable from midnight to 6 AM during the last eight months of the year. The utility pays a premium of approximately 15% above the energy cost it would otherwise offer for this flexibility. In addition, the utility also pays the start-up costs of the project when it has been shut down under these provisions (CEC [1985a]). Recently, a similar project agreed to somewhat greater dispatchability without any energy cost premium (BAF [1987]). A 220-MW project has signed a contract with PG&E that provides for complete dispatchability in all hours for a fifteen year period (Marcus [1986]). The utility pays no premium for this right, which is offered by the project in answer to regulatory concerns about excess baseload PURPA power in Northern California. The same concerns in Southern California appear to be less severe. The typical dispatchability condition on large cogeneration projects is approximately two thousand hours of curtailment of only 25% of the project's capacity, as opposed to the total shutdowns contemplated by PG&E. A representative case is the 345-MW ARCO Watson project (CEC [1986]).

The value of dispatchability is difficult to estimate and clearly depends on particular system conditions that can change over time. It can be thought of as analogous to the operating benefits of energy storage plants or other "quick start" resources. Spinning reserve requirements are reduced, load following capability is improved, and minimum loading on other plants can be decreased. The economics of these operational benefits are now being studied systematically (Decision Focus [1986]). It is therefore difficult to imagine an easily understandable "avoided cost" characterization of dispatchability. An auction procedure could certainly allow for bidders to offer dispatchability, but there would be the problem of determining what different kinds of dispatchability were worth compared to price offers.

Incorporating dispatchability into the bidding process would require sufficient analysis to differentiate this property into a number of distinct categories. Such analysis might determine, for example, three categories: (1) limited curtailment of up to 1000 hours per year, (2) "off peak" curtailment of 4-5000 hours per year, and (3) total curtailment potential in all hours of the year. Bidders proposing baseload projects would only offer type (1) dispatchability if any. Types (2) and (3) would seem to compete against each other. Some bidders might propose to "migrate" from a type (2) or (3) status to a type (1) status over a period of years. Some kind of point scoring system would be necessary to evaluate differentiated offers of this kind. As system conditions change, the values of different types of dispatchability also change. One method to deal with this problem would be to have separate auctions for baseload and dispatchable projects. Our category (1) would apply to baseload, category (3) to dispatchable. Category (2) is ambiguous. It is a policy question whether dispatchability ought to be explicitly incorporated in bid evaluation or through separate auctions. Because of its importance, however, it is unlikely that it can be treated through post-hoc adjustment, which is more appropriate to capacity valuation, where performance standards can be used to appropriately price reliability.

2.3.3 Reliability and Capacity Value

The value of electric power can be separated into a capacity or reliability component and an energy component (NERA [1977]). Pricing schemes for bidding or any other purpose can bundle these components together or separate them. The Massachusetts RFPs choose the bundling approach. In California, PURPA pricing has traditionally unbundled capacity and energy. When capacity is priced separately, measurement requires careful definition. The basic questions are: when does power have capacity value, what is the basis for that value, and how do you segment that value into components? The segmentation question is fundamental to developing performance standards that can translate a producer's actual output into a payment that reflects value to the utility. The value basis question addresses issues involving the supply and demand balance, and the variation in the total value of capacity with greater or smaller reserve margins. We begin our discussion with the value basis issue. This is an avoided cost question. (The segmentation issue leads to the question of performance standards).

The value of capacity depends on the supply demand balance. If that balance is tight, then capacity has a higher value than if there is substantial excess capacity. Traditionally, utilities have relied on probability indices to define the need for capacity and to measure excesses or insufficiencies (Bhavaraju [1982]). The baseline reliability deemed acceptable has always been somewhat arbitrary. Recently, efforts have been made to tie the baseline level more closely to impacts on customers. PG&E has developed an approach based on the cost of interruptions to customers (Hall, Healy and Poland [1986]). The PG&E method has been extended to situations in which there is "excess capacity" (Poland [1986]). The purpose of this extension is to provide a rational system for discounting the equilibrium capacity value. In equilibrium, i.e., when the system is at the appropriate baseline level of reliability, the value of capacity is measured by the costs of a combustion turbine. The combustion turbine represents the cheapest way of providing reliable capacity to the system.

Once the annual value of reliability has been determined, i.e. the combustion turbine cost has been estimated and a discount applied if appropriate, the issue of performance standards arises. Private producers contract to provide reliable capacity, but they only have value if they deliver power when the system needs it. Setting performance standards defines the match between need and the producer's output. The California PUC adopted the rule under all Standard Offers that QFs had to maintain an 80% capacity factor during the summer on-peak period to receive the full contracted capacity payment. This simple requirement is roughly equivalent to the expected performance of a combustion turbine.

A more detailed view of reliability involves differentiating performance into components. The California PUC has begun to pursue this line of investigation at the request of the representatives of the QF industry (CPUC [1986]). The California QF industry views the various aspects of capacity performance, such as emergency availability, reactive power support and co-ordination of maintenance as added benefits of QF capacity. The California utilities view these qualities as either already available under current performance standards (in particular, coordinated maintenance) or implicitly valued under current methods. The theory of implicit valuation means that these performance features should be supplied by the QF and would, in principle, be supplied by equivalent utility resources. Therefore, if a QF did not supply these features, the capacity payment should be reduced (SCE [1986]). Despite the conflict about whether these features add to or potentially reduce capacity value, both parties agree that complex measurement issues are involved.

What is significant about this discussion is that the complexity of the value issue is focused on post facto measurable performance. None of these questions enter into the auction process which the California PUC is establishing. Bidders will be chosen on an essentially bundled basis, but they will be paid separately for energy and capacity. If their capacity performance meets specified standards, they will be paid their bid price for the capacity component. If not, there will be downward adjustments. None of these performance issues needs incorporation in the bid evaluation process. The advantage of performance standards is that they address concerns about bidders from the system, for example, by diverting power to their own use during peak periods.

2.3.4 Financial Risks

The Massachusetts RFPs devote considerable attention to issues associated with the financial risks imposed on ratepayers by "front loaded" bids. "Front loading" is a situation in which the bidder seeks payment in excess of avoided cost at the beginning of his project, and compensates for this by receiving less than avoided cost in the later years. The ratepayers are exposed to the project's potential default until the initial overpayments are recovered on a present value basis. If the project is abandoned before this repayment occurs, ratepayers have lost money relative to the avoided cost. Figure 2.1 illustrates this abandonment exposure.

It is important to note that the financial risks of front-loaded bids are distinct from the risk of capacity shortage resulting from project failures. Under any scheme of capacity purchase there is always a capacity shortage risk if the supplier fails to meet his obligation. This applies to PURPA contracts as well as non-PURPA contracts. If a QF receiving front-loaded payments fails to deliver, then ratepayers are injured economically over and above the shortage costs imposed by that failure. Since the risk of shortage costs is common to all contracts, it is not a unique PURPA problem. For this reason, we ignore it and concentrate only on the financial problem of front loading.

There are a number of ways to handle the risks imposed by front loaded bids. The simplest method is to prohibit them. Such a step would reduce the number of potential bidders, but in the event of a sufficient supply this may not be harmful. Front loading may be symptomatic of a relatively undeveloped private power industry. As bidders gain experience, they may be able to structure their projects so that front loading is unnecessary. If front loading is not explicitly forbidden, it can be limited, discouraged, or compensated for in several ways. These include the use of security deposits or related instruments, or implicit or explicit discounting of front loaded bids. These various alternatives can be used separately or in combination.

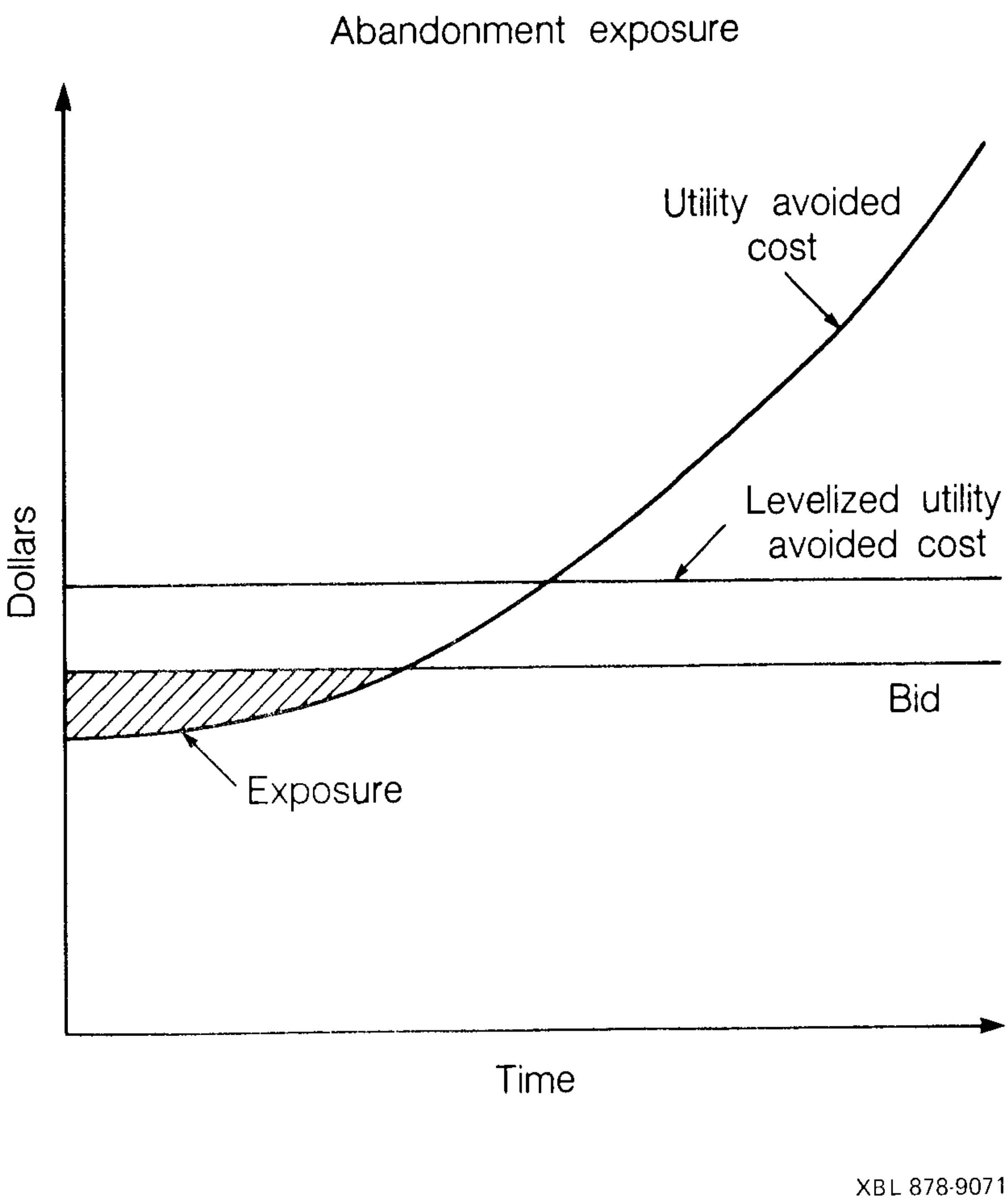

Abandonment exposure
Utility avoided cost
Levelized utility avoided cost
Dollars
Bid
Exposure
Time
XBL 878-9071

Figure 2.1

Security deposits or guarantees are essentially forms of default insurance. Front loading can be thought of as a loan from ratepayers to project sponsors. If security is required from the project developer, the ratepayer's exposure is eliminated or reduced. There are a number of ways that security can be obtained, but all of them are costly to the developer. Requiring security, therefore, is a disincentive to developers. The Massachusetts RFPs discuss a weak form of security, which is a lien on the project. In the event of default, the utility would acquire the facility. Since this is not cash security, it is less burdensome to the developer. It is, however, also worth less to ratepayers than cash security, since a project that proves uneconomic to the developer would not necessarily be economic to the utility either. Still, liens can be valuable in the event of a capacity shortage. It might be desirable to combine liens with insurance if front loading is allowed.

In addition to security, the utility can insist on a discount from avoided cost as a condition of front loading. This approach has been used to some extent in California, particularly with wind turbine projects developed in the early 1980s (Kahn [1984]). It is difficult but possible to find a reasonable basis for trading off risk against price in this situation. The mechanics of the trade off also require attention. If interest is charged on the overpayments, different methods may be used to select an appropriate rate. If the discount is deferred until after the debt to ratepayers is repaid, the benefit of discounting may never be realized in the event of default.

A final alternative, used by the Massachusetts utilities, is implicit discounting through the bid evaluation process. Massachusetts' scoring systems give lower rankings to projects that require front loading. The greater the degree of front loading, the more the scoring system penalizes a bid. In addition, these evaluation systems rank higher those projects that provide security. These indirect methods impose no revenue penalty on front loaded projects, but they require bidders to lower their prices to compete successfully. Although the qualitative effect of these scoring systems is reasonable, their precise formulation is somewhat arbitrary. WEMCO appears to penalize front loading more than BE, if only because its scoring system counts the financial risks twice rather than once. Although this may be appropriate, it will take experience to fine tune the evaluation of financial risk.

If the PURPA auction mechanism matures into a large market, then methods to accommodate financial risk will almost certainly appear. If financial risks are the limiting factor on the development of the PURPA auction market, however, then perhaps projects requiring front loading will be precluded from competing.

2.3.5 Transmission Access Cost Impacts

PURPA projects require access to the utility transmission network. In small amounts, this will probably not impose significant constraints on the power system. At some point, however, transmission can become a limiting factor. In Northern California, there appears to be more QF capacity than there is spare transmission capacity. To deal with this imbalance, a rationing system has evolved that is essentially a first-come, first-served procedure. The alternative to this for developers without access is to construct their own transmission line to a point in the network that can accommodate their output. Developers in the Stockton area are planning such a project to be funded at their own expense (Meek [1986]). An even more extreme example is the proposed 200-mile line from central Nevada to Southern California that is being sponsored by geothermal developers (Oxbow Geothermal [1986]).

The exclusive rationing and do-it-yourself approaches to transmission access represent polar extremes. Intermediate cases would involve costing transmission access either through a bid evaluation mechanism, an explicit charge to projects or both. In any of these intermediate cases, there is a transaction cost to estimating what the appropriate access charge should be. Clearly, the utility is in the position to determine this cost. Analysis of transmission systems is difficult; in particular, the marginal costs at a particular point may not even be well-defined.

Given the analytical difficulties, some indeterminacy may be introduced into the auction and development process. It is possible, for example, that a bidder would agree to pay whatever access charge was deemed appropriate if his project is selected. An after-the-auction determination might produce a cost that makes the project infeasible. One alternative to after-the-auction determination would be a case by case analysis for all potential bidders, which could be quite costly and time consuming if the number of potential bidders is large. Another alternative would be some simple pre-announced tariff which might approximate the true costs. This would have the virtue of reducing bidder uncertainty and providing some cost recovery to the utility. Striking the proper balance among virtues of these alternatives would depend upon circumstances.

The Massachusetts RFPs use a simple scoring approach to this problem by assigning bonus points to projects that are located in areas which impose no transmission difficulty. Their scoring systems give a very small weight to this factor, which implies that the anticipated scale of QF power coming to the utility will not be a serious problem. If capacity limits are approached, scoring systems will have to give greater weight to this factor.

It may also be desirable to create a transmission tariff for PURPA projects. This would have to be a posted price that bidders could take into account as another cost of production. It could substitute for a bid evaluation mechanism in much the same way as capacity performance standards substitute for a reliability scoring system. The closest analogy is the "wheeling" charges that utilities impose on PURPA projects that use one utility's transmission system to deliver power to another utility. These charges usually take a "postage stamp" form of a few mills per kilowatt hour. The advantage of such a variable charge is that it imposes no extra capital costs on developers yet can provide cost recovery to utilities.

2.3.6 Conclusions

Bid evaluation mechanisms can range from simplification through constraints to a system of weights addressing non-price factors. Simplicity encourages bidders; complexity has the potential to reflect values more accurately. Formulating complicated evaluation systems involves the inherent difficulty of evaluating non-price factors. Bid evaluation systems using weights to reflect non-price factors can be constructed with greater or less care. The Massachusetts RFPs show a good deal of thought has gone into weighing such factors. Arbitrary weighting schemes that are unrelated to economic costs can do more harm than good, however.

One method of simplifying the process is to differentiate the payment stream to PURPA projects into components that are subject to performance standards. Capacity value and transmission access seem amenable to this treatment. Financial risks and dispatchability do not. Of these two non-price features, financial risk is probably more easily incorporated into an evaluation scheme. The Massachusetts RFPs have useful approaches to this. In this case, complexity contributes constructively to evaluation of bids. Dispatchability is a more difficult problem. There are many different kinds of dispatchability, and any evaluation system must make the appropriate distinctions, which are system dependent. Of all properties of power delivery, dispatchability will be the most difficult to value either implicitly in a bid evaluation scheme or explicitly in a pricing scheme. It may be preferable to bid separately for dispatchable projects.

It is clear that the range of choices for evaluating bids is large. Much of the significance of this diversity may narrow when the process of subsequent negotiation and implementation of auction results is considered. If issues have been neglected in the evaluation phase this can be corrected in negotiations that define more precisely the obligations of producers and the payment mechanism. The anticipation of rewards in such negotiations can even lower bids.

Any bid evaluation scheme will be an approximation. If a particular quality is important in a given case, then economic efficiency requires that bidders be differentiated in that regard. The importance of local conditions suggests that no uniform or standard national practice is necessary.

2.4 Lumpiness

2.4.1 The Problem

A bid from a QF will offer a specified quantity of power at a price. Sometimes, the specified quantity will be large relative to the amount of power the utility still needs after accepting bids at lower prices. Furthermore, because of the economics of this technology the bidder may be unwilling to supply only a fraction of the specified quantity of power he offered at the same price. This presents the bid taker with a potential dilemma. Because of the potentially discrete nature of the quantities of power offered by the bids and of the technologies underlying the bids—we term this "lumpiness"—the following bid acceptance rules are not equivalent to each other:

1. Accept the set of bids that provides at least the desired amount of power at the lowest total cost provided that no bid is accepted that exceeds the utility's published avoided cost per kWh.
2. Accept a set of bids that provides no more than the desired amount of power and that minimizes the cost of that amount of power on the assumption that the utility will supply any unpurchased power at its published avoid cost per kWh.
3. Accept bids sequentially in increasing order of cost per kWh until either the cost of a bid would exceed the utility's avoided cost per kWh or the amount of power accepted would exceed the desired amount.
4. Same as Rule 3 except that if a bid is rejected, the sequence continues with consideration of bids with higher costs per kWh.
5. Accept bids sequentially in increasing order of cost per kWh until the cost per kWh of desired but as yet unaccepted power offered by a bid exceeds the utility's avoided cost per kWh of desired power (i.e., giving excess power no value).
6. Same as Rule 5 except that if a bid is rejected, the sequence continues with consideration of bids with higher costs per kWh.

Some examples may help clarify the differences. Consider the situation described in Table 2.1. Bid acceptance rule number 1 would accept Bid 2 and reject Bid 1, while the other five rules would accept Bid 1 and reject Bid 2.

Table 2.1

Desired Power: 100 MW

Utility Avoided Cost: 5¢/kWh

Bid #	Amount Offered	Price
1	80 MW	3.5¢/kWh
2	100 MW	4.0¢/kWh

If we add a third bid, creating the situation described in Table 2.2, then rules 3 and 5 accept Bid 1 only, while the other rules accept Bids 1 and 3.

Table 2.2

Desired Power: 100 MW

Utility Avoided Cost: 5¢/kWh

Bid #	Amount Offered	Price
1	80 MW	3.5¢/kWh
2	100 MW	4.0¢/kWh
3	20 MW	4.5¢/kWh

In the situation described in Table 2.3, Rules 2, 3 and 4 would accept Bid 1 and reject Bid 2, while the other three rules would accept both bids. If a third bid is added to the two in Table 2.3 to create the situation described in Table 2.4, Rules 1, 2, and 4 accept bids 1 and 3, while Rule 3 continues to accept just Bid 1 and Rules 5 and 6 continue to accept Bids 1 and 2.

Table 2.3

Desired Power 100 MW
Utility Avoided Cost 5¢/kWh

Bid #	Amount Offered	Price
1	60 MW	3.5¢/kWh
2	50 MW	4.0¢/kWh

Table 2.4

Desired Power 100 MW
Utility Avoided Cost 5¢/kWh

Bid #	Amount Offered	Price
1	60 MW	3.5¢/kWh
2	50 MW	4.0¢/kWh
3	40 MW	4.1¢/kWh

Several factors are important in a bid acceptance procedure. First of all, the procedure should promote economic efficiency. This concern has two parts. We would like the procedure to make the best economic choice among the bids offered. In addition, we would like a procedure to send the right incentive message to the bidders so that bidders with lower costs will submit winning bids. In addition to economic efficiency, we must be concerned with fairness and the appearance of fairness. Furthermore, we want the procedure to be operational (i.e., unambiguous) and reasonably simple. Finally, it may prove to be helpful if the procedure is stable in the sense that if one or more accepted bids are withdrawn, the acceptance procedure applied *de novo* to the unwithdrawn bids does not, or at least is less likely to, lead to the rejection of any bid that was acceptable before the bid withdrawal occurred. These preferences are in conflict, however, and an acceptance procedure must compromise among them.

Next, we discuss various ways of dealing with lumpiness or of reducing it. After those discussions, we examine how some of the individual measures interact with each other and then assess overall approaches to the bid decision process.

2.4.2 *The Measures*

We have considered four measures that would reduce lumpiness or the difficulties it poses. Some of the measures also have advantages that extend beyond their effect on the lumpiness problem. Two of the measures are directed at reducing the lumpiness of bids and two at dealing with the lumps that remain in ways that are simple, fair and economically reasonable.

2.4.2.1 *Multiple Bids*

The first lumpiness reduction measure is to allow and even encourage multiple bids by a single bidder. To the extent that bidders do this, the utility receives fewer bids involving large quantities and more bids involving small quantities. However, even without the lumpiness problem, both the bidder and the utility stand to gain if, technology permitting, the bidder offers capacity incrementally beyond the amount that results in the minimum average cost per kWh.

An example will illustrate this. Suppose that a small bidder can produce one MW for 4¢ per kWh and a second MW for 6¢ per kWh. Suppose the auction is a first-price auction and the bidder estimates the cutoff acceptance price to be equally likely to fall anywhere between 4¢ and an announced avoided cost maximum of 8¢. The simple model of this situation presented in Appendix B shows that the optimum bid is half way from the bidder's cost to the maximum price. If the bidder submits a single bid for 2 kW its average cost is 5¢, its best bid is 6.5¢, its probability of winning is 3/8, and its expected profit is proportional to $(6.5-5)\cdot\frac{3}{8}\cdot 2=1.125$.

If, instead, the bidder submits two bids, each for 1 MW, the best bids will be 6¢ and 7¢, these bids will have probabilities 1/2 and 1/4 of winning, and the bidder's expected profit will be proportional to $(6-4)\cdot\frac{1}{2}+(7-6)\cdot\frac{1}{4}=1.25$. This is 11% more. The extra expected profit for the bidder is matched by an equal expected savings to the utility. If the cutoff price is between 6.5 and 7¢ the utility will end up paying 6¢ per kWh for 1 MW from this source instead of 6.5¢ for 2 MW. If the cutoff price is between 6 and 6.5¢, the utility will get 1 MW from this source at 6¢ instead of paying the cutoff price. Each of these changes is a gain for the utility. Any other cutoff price results in no difference in either quantity or price for the utility.

2.4.2.2 *Downsizing*

Another measure is "downsizing." This measure would reduce lumpiness by allowing a marginal bidder whose bid is too big to reduce the quantity (without changing the price per kWh) to a level that would allow the bid to be accepted. If the reduction is unacceptable to the bidder, nothing has been lost. However, if the bidder accepts, the utility will have gotten the lowest cost power offered to it.

Again, an example may help. In the example given in Table 2.1 above, Bidder 2 is the marginal bidder. If Bidder 2 would prefer to sell 20 MW at 4¢/kWh to selling none, then the utility has obtained its desired 100 MW at an average cost of 3.6¢/kWh—the lowest possible cost given the bids, even ignoring the lumpiness issue completely.

The bidder may be willing to sell 20 MW at 4.0¢/kWh because its technology is modular so that its cost is proportional to capacity or nearly so. Alternatively, it may have moderate economies of scale but, none the less, have a sufficiently low cost that 20 MW at 4¢/kWh is still attractive. A third possibility is that the technology of Bidder 1 is flexible and that Bidder 2's costs are low enough that Bidder 2 can afford to buy from Bidder 1 the right to supply some of the 3.5¢/kWh electricity Bidder 1 is contracting for. For example, Bidder 2 might buy the right to 30 MW of capacity so that each supplied the utility with 50 MW—Bidder 1 at 3.5¢ and Bidder 2 at an average cost of 3.7¢.

2.4.2.3 Tolerance

A third way to deal with lumpiness is to allow a tolerance in the desired capacity. For example, Southern California Edison proposed to the California PUC that when it sought a given amount of electricity, it would accept bids below its avoided cost in increasing order of cost until the next bid acceptance would increase the total quantity of bids accepted beyond the amount of its requirement. It proposed that the last bid be accepted anyway if its acceptance would not raise the total quantity to more than 110% of the required power and be rejected otherwise. Thus, using this rule, Southern California Edison would accept both bids in the example shown in Table 2.3 above. A plausible rationale for this rule is that the power requirement is known only within 10% so this degree of flexibility has no significant adverse effects.

2.4.2.4 Demand Curve

More generally, it is reasonable to assume that the utility values power beyond the desired amount. It is possible for the utility to develop a demand curve for such power and use it in its bid acceptance procedure. This fourth measure would add some complexity to the bidding procedure, but it would also add some economic rationality and help in dealing with lumpiness.

For example, a utility that required 100 MW and had an avoided cost of 5¢/kWh for that quantity might also have an incremental value of 4¢/kWh for an incremental

MW. If faced with the bids shown in Table 2.1 above, the utility would accept both bids. In general, the utility would accept or reject a marginal bid; (i.e., the bid that, if accepted, would put it over the desired quantity) based upon a comparison of its economic situation with respect to avoided cost with and without that bid.

2.4.2.5 Measure Interactions

Each of these four measures has value on its own. However, it is useful to consider how various measures interact. It is desirable to integrate measures in a way that avoids unnecessary anomalies and, in particular, unnecessary "discontinuities." By a discontinuity, we mean a large change in the cost incurred by a utility being caused by a small change in the price or quantity of a bid. (There will be discontinuities, of course, in the choice of winning bids). Discontinuities in cost suggest that, on one end or the other, the cost could be improved by a small change.

The downsizing measure can reduce discontinuity when used without the demand curve measure, which also removes discontinuities. Without the demand curve measure, a small increase in the quantity of a bid can make it unacceptable and force the utility to accept a much higher cost for the power it would have supplied. Since a bidder is likely to accede to a small downsizing requirement, this measure will normally eliminate discontinuities.

The demand curve measure has similar properties by itself or in *proper* combination with other measures. In particular, care must be exercised in integrating the tolerance and demand curve measures. These measures may be viewed as partial substitutes for each other or as complements. If they are both used, care must be taken in defining them so that a small increase in the quantity of the marginal bid beyond the tolerance level does not result in a large decrease in its apparent valuation. Such a decrease can be avoided by valuing power in the tolerance range at avoided cost or by, at least, not penalizing a bid's evaluation for shortfalls relative to avoided cost in this range.

2.4.3 Auction Design

We have considered two opposite auction design philosophies for dealing with lumpiness as well as variants and combinations of them. One philosophy is to take the bids as given and have the utility accept those bids whose selection will solve exactly the problem of minimizing its total cost for its quantity requirement. In this approach, the "hard" nature of the quantity limit can lead to results that are not as efficient economically as their "cost minimizing" definitions might lead one to expect. This approach completely ignores any unfairness implicit in accepting a high-priced bid while rejecting a lower-priced one. It also ignores the fact that a bid withdrawal may lead to the rejection of previously accepted bid. In addition, it ignores any willingness of a bidder to accept a partial contract. It is not computationally simple, but as discussed in Appendix C, it is computationally manageable. Because of the extra variability it induces in the prediction of the maximum acceptable price for a bid, it will tend to increase the variability of the bids by giving relatively high bidders an incentive to bid higher (they still might win) and relatively low bidders an incentive to bid lower (to lower the risk of losing).

The other philosophy is to rank the bids by cost per kWh, accept bids in order of increasing cost until the desired quantity is reached or it no longer pays to accept any more, and to use as many as possible of the measures discussed above for reducing lumpiness. In its pure form, this approach stops with consideration of the marginal bid, and is fair in the sense that it never accepts a higher bid than a rejected one and stable in the sense that withdrawal of a bid will never lead it to reject a bid that would have been acceptable without the withdrawal. It takes advantage of a marginal bidder's ability to cope with a partial acceptance, and it is computationally simple. However, unless the marginal bidder is willing to accept a partial award, it does not guarantee the utility the lowest possible cost set of the given bids for meeting the required quantity.

There is a potentially attractive variant of the second approach that sacrifices the stability property with respect to inframarginal bids in return for some economic improvement. In it, the utility follows the second procedure except that, if the marginal bid is not accepted even in part, it then goes on to consider other bids. Thus, for example, in the situation described in Table 2.5, if Bidder 2 refused to downsize sufficiently, bids 3 and 4 would be accepted and Bidder 5 would be given an opportunity to downsize. Some aspect of fairness is lost too, because Bidder 2's price is lower than Bidder 3's and Bidder 4's. On the other hand, given the existence of Bidder 1's bid, Bidder 2's bid is not as attractive to the utility, and Bidder 2's low price has obtained for Bidder 2 the right to adjust quantity to make it as attractive. Having declined this opportunity, Bidder 2's claim for having been treated unfairly is weak.

Table 2.5

Desired Power 100 MW
Utility Avoided Cost 5¢/kWh
2¢/kWh beyond 100 MW

Bid #	Amount Offered	Price
1	60 MW	3.5¢
2	100 MW	4.0¢
3	20 MW	4.1¢
4	10 MW	4.2¢
5	50 MW	4.5¢

An interesting question that must be answered in following this approach is by how much Bidder 2 would have to downsize. There are at least three possible ways of calculating the required downsizing. First, we could do so assuming that there are no other bids. Under this assumption, the first 40 MW of Bidder 2's bid saves the utility 1.0¢/kWh and every additional MW costs the utility 2.0¢/kWh. Therefore, if the second bid were scaled down to 60 MW ($=40+40\cdot\frac{1.0}{2.0}$), the utility would break even.

Second, we could calculate the required scale down taking account of other bids but not assuming any other bid will be scaled down. Under this assumption, the utility's average cost for the last 40 MW would be 4.35¢ (20 MW at 4.1¢, 10 MW at 4.2¢, and 10 MW at 5.0¢). Thus, the required scale-down would be to 47 MW ($=40+40\cdot\frac{.35}{2.00}$). (If there is a 10% tolerance on accepted quantity so that the utility is required to accept up to 110% of its stated requirement, then that tolerance would supercede this calculation, and the required scale-down by Bidder 2 would be only to 50 MW.)

A third possible calculation of required scale down would assume, at least tentatively, scale down by later marginal bidders. Under this assumption, the utility's average cost for the last 40 MW would be 4.225¢/kWh (20 MW at 4.1¢, 10 MW at 4.2¢ and 10 MW at 4.5¢), and the required scale down would be to 44.5 MW ($=40+40\cdot\frac{.225}{2.000}$) unless superceded by a tolerance of more than 4.5%. Presumably, under this rule a bidder's rejection would be tentative. If a subsequent marginal bidder refused to scale down, the bidder would then be offered a second, less strict scale down requirement based on the new situation. If the rejection were not tentative, both fairness and economic efficiency issues would arise.

If the "pure" second philosophy is followed in that subsequent bids are never considered after a marginal bid is rejected, then the first rule for deciding the required amount of downsizing is clearly appropriate. Under the variant procedure, we prefer the second rule. This makes more economic sense than the first given that subsequent bids will be considered. We prefer the second rule to the third because it maintains strictly the sequential nature of the bid acceptance and because it avoids the possibility of strategic decision making by a bidder faced with a downsizing decision. In the example discussed above, strategic decision making would occur under the third rule if Bidder 2 declined to downsize to 44.5 MW even though this was economically preferable to losing the auction because it doubted that Bidder 5 would in fact downsize and it preferred to downsize only to 47 MW.

Overall, we prefer the second philosophy to the first. We believe that, in combination, the measures we have suggested will reduce the lumpiness problem significantly. We believe the fairness, stability, and simplicity are worthwhile advantages. On the other hand, we do not believe that they are absolutes. Hence, we tend to prefer the economic advantages of the variant of the second philosophy to its pure form.

Finally, we note that since there are many different plausible bid acceptance procedures, a great deal of difficulty and dispute may arise if acceptance procedures are not explicitly defined in advance. Appendix E contains an example of such an explicit definition.

2.5 Frequency of Auctions

To some extent, the frequency with which a utility holds auctions to purchase PURPA power will be determined by perceived needs for additional capacity. As the events of recent years have demonstrated, perceived needs can develop unevenly as expectations of demand growth change and adjustments for prior misestimates are made. However, to the extent that a utility anticipates a need for new capacity, it can try to meet that need with relatively infrequent auctions to buy large amounts of power, or relatively frequent auctions to buy smaller amounts. To the extent that, everything taken into account, there are significant economies of scale remaining in utility constructed power plants, the utilities' avoided costs will be lower if the auctions are sufficiently infrequent that large plants are economic. However, PURPA power will often not have as large economies of scale. Furthermore, it may be disadvantaged by long delays between auctions. In particular, the opportunity for integrated cogeneration in a new industrial facility may be lost if there is no auction near the time when the industrial facility design decisions are being made. Hence, there is reason to hold PURPA auctions with some regularity.

While it is difficult to be quantitative, it is clear that there are disadvantages to both too frequent and too infrequent auctions. In addition to the concern about economics of scale in utility plants already mentioned, too frequent auctions may encourage collusion if they have the same or significantly overlapping participants. Each bidder has the opportunity to take into account the way that his bid in one auction will affect those of his competitors in future auctions. Oren and Rothkopf [1975] have shown that if the auctions are frequent, the effect of such behavior can be to increase bids significantly.

A secondary complication of too frequent auctions may be difficulty in calculating avoided cost. The problem arises because with frequent auctions the utility may perceive that the cheapest way to meet its capacity need is to wait until a later PURPA auction and buy the power offered then. The less frequent PURPA auctions are, the less likely this is and the more appropriate is the convenient and traditional course of avoiding any allowance for this in calculating avoided cost.

If auctions are too infrequent, three problems may arise. One problem has to do with the economics of utility capacity additions. If these additions are deferred too long because of infrequent auctions, total utility costs will be higher than necessary. Another problem has to do with PURPA projects with a limited time frame. For example, a manufacturer planning a new plant may be considering including cogeneration capability. There is a limited period during which his plant design decisions are being made. If there is no PURPA auction during this period, then the opportunity for integrated cogeneration is likely to be lost. When an auction is eventually held, cogeneration from this plant would carry retrofit costs. Finally, if many utilities waited many years between cogeneration auctions, the stability of businesses capable of providing cogeneration might be undercut.

On balance, it would seem advisable for utilities to hold auctions at least every two or three years. This period is long enough to allow the utilities' demand estimates to be clarified and to allow decisions from the previous auction to be made. In addition, it would be hard to develop tacit collusion in auctions that far apart. Finally, most large new plants with cogeneration potential can be fit into sueh a schedule.

III. A CASE STUDY

3.1 Introduction

The purpose of this section is to illustrate the PURPA auction process in some detail by showing an example of how it might work in practice. This example is necessarily stylized and hypothetical. It is designed to focus attention on the procedures involved in PURPA auctions, the unknown factors, and some of the principal sensitivities. The factual background is drawn largely, but not exclusively, from California information.

The case study is divided into four components. The first two involve cost estimation, and the second two focus on the bidding process and acceptance procedure. The first step is the estimation of the utility's avoided cost. We study the cost structure of the Southern California Edison Company (SCE), using publicly available data, and following procedures set out by the California Public Utilities Commission (CPUC). The parallel step for the bidder is to characterize the cost functions facing bidders. These are based primarily on the assumption that bidders will be cogenerators.

The auction format we assume is a first-price or discriminatory auction based on bidders' offers in terms of a single price per kilowatt hour. This procedure departs from California bidding protocol in two ways. First, the California PUC has called for a second-price auction. For the reasons given in Section II above, we do not believe that the desirable theoretical properties of the second-price auction will be realized in practice. Instead, we use the first-price procedure, which necessitates an explicit representation of the bidder's strategy. Secondly, our bid will be based on a single price specified in cents per kilowatt hour, representing the bidder's first year price. The CPUC protocol requires bids in dollars per kilowatt of capacity offered. Such bids cannot exceed the avoided resource's capital costs. The CPUC protocol requires bidders to make estimates of their life-cycle costs. Our procedure abstracts from this problem. The simplifications we adopt help us to focus on strategic questions.

Our model of the bidder's strategy is based both on costs and the bidder's expectations of the "cut-off" bid. This expectation is necessarily uncertain, so we explicitly represent a probability distribution around the expected cut-off bid. A procedure is developed to produce an auction outcome that is consistent with bidder's expectations. This will enable us to examine the sensitivity of results to these expectations.

Finally, we focus on the problem of lumpiness in the bid acceptance process. Because capacity bids are indivisible, it is possible that the marginal bidder will offer capacity in excess of the remaining need requirement after all previous bids have been accepted. There are a number of procedures to ameliorate this problem. We will examine some of them in the specific context of outcomes from our simulated auctions.

The case study is organized in the following manner. We begin with the utility avoided cost analysis in Section 3.2. Data and methods will be reviewed in the context of SCE resource plans and CPUC procedures. We will extend these procedures to estimate a "demand curve" for PURPA purchases. In Section 3.3, we present cost curves for cogenerators. These are based on a number of technologies and process steam loads. Section 3.4 is our model of a first price auction where bidders have the cost curves developed in Section 3.3 and exogenous expectations about the cut-off bid distribution. A number of different cases are tested. Section 3.5 examines the lumpiness problems arising from the results in Section 3.4. Different procedures for accepting the marginal bidder will be illustrated in the context of specific results.

3.2 Avoided Cost Estimation

There is no generally accepted procedure for identifying the long-run avoided cost for an electric utility. Differences in analytic methodology are substantial, and ambiguities about the use of data are considerable. These problems are among the reasons for dissatisfaction about the implementation of PURPA rules. In our case study, we follow primarily the approach taken by the California Public Utilities Commission (CPUC Decision 86-07-004, July 2, 1986). The goal of this approach is to identify particular avoidable resources that QFs could displace. The identification process is essentially a resource planning exercise in which potentially avoidable plants are subject to a cost-effectiveness test.

There are preconditions to conducting this test, however. These include the specification of numerous resource planning assumptions which characterize a starting point for analysis, or base case. The base case requires estimates of expected demand growth, future fuel prices, the availability of economy energy and previously contracted QFs, and, finally, the cost of capital. Once these assumptions are made, production simulation techniques are used to determine when cost-effective resources can be added to the system. The size and timing of these resource additions determine when a PURPA auction should occur and how much capacity should be purchased. The total cost of the resource avoided becomes the upper bound on acceptable bids.

For our purposes, it is more important to focus on the cost-effectiveness test for new resources than to delve into the details surrounding the specification of the base case. The salient fact about the base case is that the relevant assumptions are uncertain and controversial. QFs, utilities and regulatory staff have different opinions about key variables. These differences cannot be resolved. What is important for auction methodology is extending the cost-effectiveness test so that a more complex characterization can be given to the identified avoided cost. The basic goal of this extension is to accommodate the lumpiness issues discussed in Section 2.3 above. We need a characterization of the avoided cost value beyond the auction quantity to provide for bid acceptance procedures. To meet this need, we summarize the cost-effectiveness test adopted by the CPUC and show how it can be extended. This is the subject of Section 3.2.1. In Section 3.2.2, we summarize our procedure for establishing a base case. This discussion will review our assumptions relative to the perspective of other somewhat similar cases. Finally, Section 3.2.3 presents the results of our avoided cost estimation.

3.2.1 Cost-Effectiveness, the Identified Deferrable Resource and Extensions

The basic trade-off resource planning is determining when the fixed costs of new facilities are justified relative to the fuel savings that they produce. The practical details of making this trade off are complicated by the variety of potential new facilities and the timing of additions. The CPUC methodology breaks the process down into two distinct phases. First, the potential new facilities are tested for cost effectiveness against a base case resource plan that has only a limited number of very low-cost resource additions. (See Section 3.2.2 for further discussion of this base case.) By the nature of this test, all new facilities are likely to be cost effective. Next, the different new facilities are ranked relative to one another. This ranking depends on the expected output of each facility. For simplicity, we consider only baseload generation. The least expensive life-cycle cost facility becomes the avoidable plant. In the language of the CPUC methodology, this plant is called the Identified Deferrable Resource (IDR). Finding the IDR identifies the cost basis for a PURPA auction, but not the timing of the resource need. Timing is determined by the next phase.

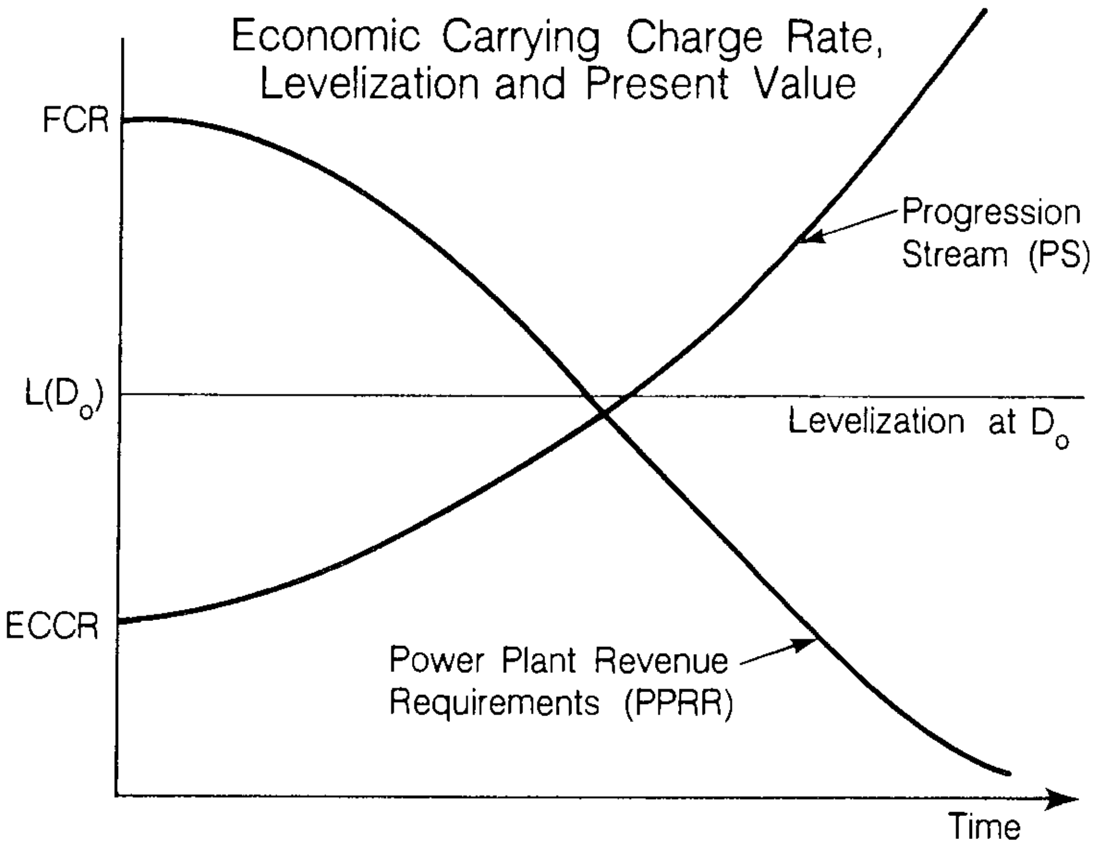
The tests performed in both phases require that facilities be represented by plant characteristics including capacity, outage rates, capital costs, etc. The capacity specification is important because scale economies in capital costs influence the choice of optimal facility size. A full examination of the scale economy potential is excessive. The more practical choice is to select a reasonable capacity for each facility tested in the first phase. The results of the first phase will determine an IDR to be examined in the second phase. In the second phase, the fuel savings of the IDR in its first year of operation are traded off against its capital costs. When the benefits balance the costs, it is the optimal time to add the IDR. This trade off is sensitive to the capacity of the IDR. The larger its capacity, the smaller the fuel savings of its last unit of capacity. This diminishing returns effect may have an important influence on the outcome of the timing test. We will return to this effect when we consider extending the IDR method.

The CPUC timing test balances the reliability and fuel savings benefits of the IDR in its first year of operation against the fixed costs calculated by the "economic carrying charge method" (ECCR). The ECCR method differs from both the traditional method of calculating fixed costs used for revenue requirements and the method used for levelized costs. ECCR is designed to produce a stream of fixed costs that escalate at some predetermined rate of increase over the investment lifetime. The present value of fixed costs calculated by the ECCR method is designed to be the same as that calculated by either of the other methods. Figure 3.1 shows the three methods.

The ECCR method is designed to provide an approximation to competitive market pricing that would be appropriate for marginal cost purposes. A full discussion appears in the marginal cost pricing literature (NERA [1977]). The ECCR fixed charge rate during the first year of operation is intended to yield the minimum recovery of capital costs that a competitive firm might expect on an investment. This level rises over time because other firms investing later must pay higher costs for the same investment as a result of the generally escalating price level. Thus, the exogenous rate of escalation used with the ECCR is supposed to be a forecasted general rate of inflation net of technical progress. The ECCR method has been used for PURPA capacity pricing in Texas and Montana (Texas Utilities [1985], Montana PSC [1984]) as well as in marginal cost pricing studies for retail rates.

The timing test for the IDR is reasonably straight forward. An IDR which fails the test in a given year is more likely to pass it in the next year because load growth and fuel price increases will raise the benefits of the IDR faster than its costs will increase. As indicated above, the capacity specified for the IDR will play an important role in the timing test. Scale economies at the plant level suggest that larger unit sizes are more economic. Diminishing returns in fuel savings argue for smaller rather than larger unit sizes.

Once the IDR has been found and its timing determined, all the parameters necessary for a PURPA auction have been fixed. The capacity of the IDR is the amount of power to be purchased. The cost-effective time to add the IDR is the date at which power should be supplied. The total cost of the IDR is the upper bound on bids from potential suppliers. Given the problems that may arise because of lumpiness, however, it is desirable to characterize the value of power outside these limits. The methodology used to identify the IDR cannot be directly extended to capture the value of power beyond the IDR limit. It is necessary to use a somewhat different approach.



$$PV_{D_o}(\Sigma L) = PV_{D_o}(PPRR) = PV_{D_o}(\Sigma PS)$$
$$PS_{i+1} = (1+e)\, PS_i$$
$$ECCR = f(D_o, e)$$

XBL 865-10092

Figure 3.1

We would like to express the value of some block of capacity beyond the IDR as a fraction of the IDR cost. The best way to achieve this comparison is to rely on a alternative formulation of the cost-effectiveness test. We know that the fixed costs of the IDR have the same present-value as its fuel savings. This is the definition of an optimally timed resource addition. To find the value of X MW beyond the IDR, it is logical to add this amount of capacity to a resource plan including the IDR, give it the same fuel costs as the IDR and compute its fuel savings. We can then compare the present value of the fuel savings of the X MW block with those of the IDR over the life cycle. The ratio of these two values will allow us to calculate the value of the X MW block. This method is used and the results presented in Section 3.2.3.

3.2.2 Base Case Scenario

The Base Case Scenario we use relies heavily on the documents submitted by SCE in the CPUC hearings which established the methodology described in the previous section. SCE ran an updated version of its Fall 1985 Resource Plan and supplied summaries of the PROMOD simulation model results and inputs to document its base case scenario. The only resources to be added to the existing utility system in this scenario are those which are either under construction, are demonstrably non-deferrable or are QFs with existing contracts. Other parameters of the resource plan are designed to be consistent with supply planning and demand forecasting performed by the California Energy Commission (CEC).

It is useful to compare the SCE scenario to somewhat similar forecasts developed by the CEC for the purpose of power plant siting. The CEC as part of its Electricity Report process constructs scenarios that also require forecasts of future QF development and the availability of low cost resources. A snapshot comparison of the two scenarios for the forecast year 1995 illustrates the range of uncertainty in crucial variables and even differences of interpretation concerning nominally similar quantities. Table 3.1 summarizes some of these differences. Some of the entries in this table are simulation input values (such as demand, oil price, and QF forecast); others are simulation outputs (such as oil and gas consumption, Northwest and Southwest economy energy consumption). In addition to these differences, SCE includes a hydro system re-optimization called the Big Creek Expansion Project which the CEC does not. There are also different representations of an exchange agreement with the California Department of Water Resources. These differences and Table 3.1 should make it clear that even relatively simple supply forecasting is subject to considerable uncertainty.

Table 3.1

Comparison of SCE and CEC 1995 Forecasts

	SCE	CEC
Total Production (GWh)	93,689	89,165
QF Output (GWh)	17,402	22,632
NW Economy Energy (GWh)	3,845	3,348
SW Economy Energy (GWh)	10,300	4,126
Oil/Gas Price ($/MMBtu)	6.90	7.92

There is no definitively correct scenario that should be used. For convenience, we will follow the SCE representation in most details. One principal conclusion that SCE claims to follow from their scenario is that no IDR exists up to 1994. This conclusion is somewhat less likely in the CEC scenario because it assumes somewhat less Southwest economy energy availability. In both scenarios, an IDR becomes more likely after 1995. In particular, the SCE Resource Plan shows generic purchases in 1997 and coal capacity added in 1998. The CEC scenario shows oil and gas resources on the margin in 1997 more than 96% of the time.

3.2.3 Results

Table 3.2 shows the results of our calibration tests, which compare SCE results from the PROMOD model with our UPLAN characterization. The production of resources is aggregated by fuel type. Baseload resources such as Palo Verde and SONGS nuclear units and Navaho and Mohave coal plants will agree in any set of simulations. Input variables are also adjusted to guarantee agreement on QFs, Other Coal, Hydro and BPA purchases, and other miscellaneous categories. The marginal resources are a more important test. For the SCE system, these are oil and gas units and economy energy purchases from the Pacific Northwest (PNW) and Southwest (SW). In aggregate, these agree quite closely. The disaggregated results show UPLAN taking more off-peak energy from the Pacific Northwest than PROMOD and less from the SW off-peak. These deviations are largely offsetting and have no cost consequences because the resources are priced similarly. Detailed results from the calibration are given in Appendix H. Given the close agreement, we can use UPLAN to perform the cost-effectiveness tests for the IDR with reasonable confidence.

BENCHMARK RESULTS - 1995 in GWh

	PROMOD	UPLAN
PV/SONGS	14,563.1	14,544
Navaho/Mohave	8,361.9	8,372
Other Coal	2,291.2	2,310
QFs	17,814.6	17,842
Hydro/BPA	13,109.1	13,200
Econ CPP	1,735.6	1,720
Misc	580.1	567
Econ PNW/SW	14,144.7	14,181
Consisting of:		
PNW-on peak	1,288.3	1,421.8
PNW-off peak	2,556.6	3,579.7
SW-on peak	2,220.3	2,522.5
SW-off peak	8,079.5	6,656.8
Oil and Gas	20,931.6	20,942
Peakers	61.4	49
Other Misc	98.6	90
	93,691.9	93,688
Unserved		3.4

The IDR is a 500-MW coal plant. Data on the cost performance of such a facility are based on SCE's characterization of the CEC's Common Forecasting Methodology VI (CFM VI) Form R-10. The 1982 installed cost of such a plant is estimated to be $1,614/kW. Escalating this to 1996, the capital cost would be $3,341/kW. These values are about 30% higher than what is estimated by the Electric Power Research Institute's Technical Assessment Guide (EPRI [1986]). The relatively high cost of the IDR reflects environmental effects indirectly. A coal plant to serve Southern California must be sited at some distance to minimize fuel cost and pollution. This imposes considerable transmission requirements and associated costs.

The cost-effectiveness test balances the fuel savings of the IDR against its capital costs. The relevant capital costs must exclude the part of the plant that serves reliability purposes. The usual procedure is to subtract the costs of a peaking turbine from the coal plant costs and treat the remaining costs as "energy related capital." The rationale for this adjustment is that the costs beyond the value of the combustion turbine reflect the investment necessary to use a low-cost fuel. SCE estimates the cost of a combustion turbine at $381/kW in 1982. The escalated 1996 value is $789/kW, leaving $2,556/kW in energy-related capital. The total cost of the IDR includes the revenue requirements associated with the capital investment. On a present-value basis, these amount to $1,777 for every $1,000 of capital. These calculations are given in Appendix H. They are based on SCE's estimated fixed charge rate of 22.9%, a book life of 35 years for the plant and a discount rate of 13.3%. For a 500-MW plant, the total 1996 present-value revenue requirement for energy-related capital is $2,271 million. The first year cost-effectiveness test requires that this present value be apportioned using the "economic carrying charge rate" method. For a 35-year stream escalating at 5% annually and discounted at 13.3%, the economic carrying charge is 7.83%. For the SCE IDR, this means $178.5 million in fuel savings must be generated in the first year.

Fuel savings are calculated using UPLAN simulations for 1996. The same resource plan used for the calibration is used in this case, but fuel prices and loads are increased to represent 1996 conditions. The fuel savings calculation has two components. The direct component consists of the change in total production costs between two cases, one without the IDR and one with the IDR. The indirect component involves the effect of the IDR on the prices paid to existing QFs. Avoided cost pricing means that existing QFs are paid the marginal cost of production. As resources are added to the system, this cost decreases and so do the payments to QFs. In a system like SCE, where existing QFs comprise a substantial fraction of capacity, the indirect effect can be quite large.

Direct savings are calculated to be $111 million. Indirect savings had to be estimated by approximating marginal cost changes. The UPLAN marginal cost report is not reliable for our representation. We use UPLAN's chronological model to represent economy energy resources. This is necessary to capture the difference between on-peak and off-peak availability that is represented in PROMOD. The current version of UPLAN does not incorporate chronological resources into the marginal cost report. Appendix H gives details of our approximation. The result is a charge of 4.7 mills/kWh in marginal cost as a result of the IDR. This does not apply to the entire production of existing QF resources because some of them are paid on the basis of fixed price contracts that do not adjust to marginal cost. The California Energy Commission has estimated that 68% of

SCE's projected QF capacity is based on marginal price contracts (Regional Economic Research [1986]). Using this estimate, we calculate indirect savings of $56 million. Two other minor adjustments are also made. First, there are differential line losses associated with service area QFs compared to a remotely sited IDR. Second, SCE increases QF prices by 3.5% when burning natural gas to correct for PROMOD heat rates based on oil consumption. Together, these adjustments add 6.5% to total fuel savings. The combined value is then $178 million. This is the same as the economic carrying charge rate times the present-value revenue requirement of the IDR energy-related capital. In short, the IDR is cost-effective in 1996.

Once cost-effectiveness is established, the IDR costs must be translated into a form amenable to an auction. The CPUC postulates bidders quoting some fraction of the IDR capital costs as their bids. This procedure places the burden on bidders to assess fuel price risks and other long-term aspects of their project's economics in formulating a bid. For simplicity, we neglect these long-term problems and treat only the first-year costs of both the IDR and the potential cogenerator. The cost functions of bidders will be formulated in terms of 1996 costs on a cents per kilowatt hour basis. Therefore, we will also translate IDR costs into the same units.

The 1996 avoided cost is the sum of three components, two for energy and one for capacity. The energy value is the sum of fuel costs and energy-related capital. The capacity value is the annualized cost of a combustion turbine. From the previous analysis, the energy-related capital of the IDR has a 1996 value (and cost) of $178 million, in nominal terms, or 6.33 cents/kWh. The fuel cost of the IDR is 2.44 cents/kWh. The total energy value is 8.77 cents/kWh. The capacity cost is the economic carrying charge rate times the present value of revenue requirements for a combustion turbine. This is $55 million. In this case, we will levelize the capacity value. Levelization is a front-loading technique that has been more accepted by California regulators than the levelization of energy payments. In part, the reason for this is that smaller sums of money are involved in levelizing than in front-loading. Levelizing the capacity value results in a per-unit contribution of 3.02 cents/kWh. This yields a total 1996 value of 11.79 cents/kWh. For simplicity, we round this off to 12 cents/kWh, which will represent the upper bound for bidders in our simulated auctions.

Finally, we estimate a value for electricity beyond the IDR. Because we levelize the capacity payment within the IDR quantity, it will be advisable to assign no capacity value beyond the IDR. The only value will be energy. We simulate SCE adding 200 MW of additional coal capacity beyond the IDR and calculate its fuel savings. The result is a direct fuel savings which is 89% of that calculated for the IDR. Assuming that indirect savings scale in the same manner, we calculate that the energy-related capital component of this increment is worth 5.63 cents/kWh. Adding 2.44 cents/kWh in fuel cost results in a total value of 8.07 cents/kWh for 200 MW beyond the IDR. We will round this off to 8 cents/kWh for use in our auction simulations. For simplicity, it may be helpful to think of this value as approximately the short-run marginal energy cost. In reality the decline in value with additional power would probably be more gradual. Capacity beyond the IDR would have some value greater than zero. We adopt the assumption of zero value to highlight the quantity constraint and lumpiness problem. Even if our representation is a bit extreme, it does illustrate a phenomenon that eventually occurs, i.e., at some point capacity value is zero, and that point is not too much beyond the IDR quantity.

3.3 Bidders' Cost Functions

The parallel problem to the utility avoided cost estimation is the characterization of the bidders' cost functions. It is necessary to represent the bidders by cost functions because we want to model their behavior with respect both to the prices they bid and the quantities they choose to offer. The bidders must make a capacity choice that depends on both their estimates of the cut-off price and their own costs. This is most conveniently illustrated by Figure 3.2, which shows the cost functions of a gas-fired cogenerator facing 1996 cost conditions that are consistent with the economic scenario we used for the utility avoided cost estimate.

The average cost curve lies below the marginal cost curve and does not have as steep a slope as the latter. The rational bidder will choose capacity at the point where his bid intersects his marginal cost curve. If he chooses a capacity below that level, he sacrifices potentially available profits. If he chooses a greater capacity, it loses money incrementally. Appendix D presents the optimal condition for the simultaneous choice of price and quantity. For simplicity, in this case study we use a bidder's estimate of the cutoff bid in his capacity determination rather than attempt to have him optimize capacity and bid simultaneously.

Figure 3.2 shows how the bidder's estimate of the cut-off price affects his choice of capacity. Suppose he estimates that the highest winning bid will be 10 cents/kWh (the line E1); then the maximum capacity he would choose is Q1 or 75 MW (allowing for indivisibilities). If his estimate is 11 cents/kWh (the line E2), then the minimum capacity he would choose is 125 MW. Given the shape of the marginal cost curve, E2 implies a capacity that could be as big as 150 MW. Thus, it is clear that the bidder has a substantial range of capacity choices with this cost configuration, depending on his expectations of the behavior of his competition.

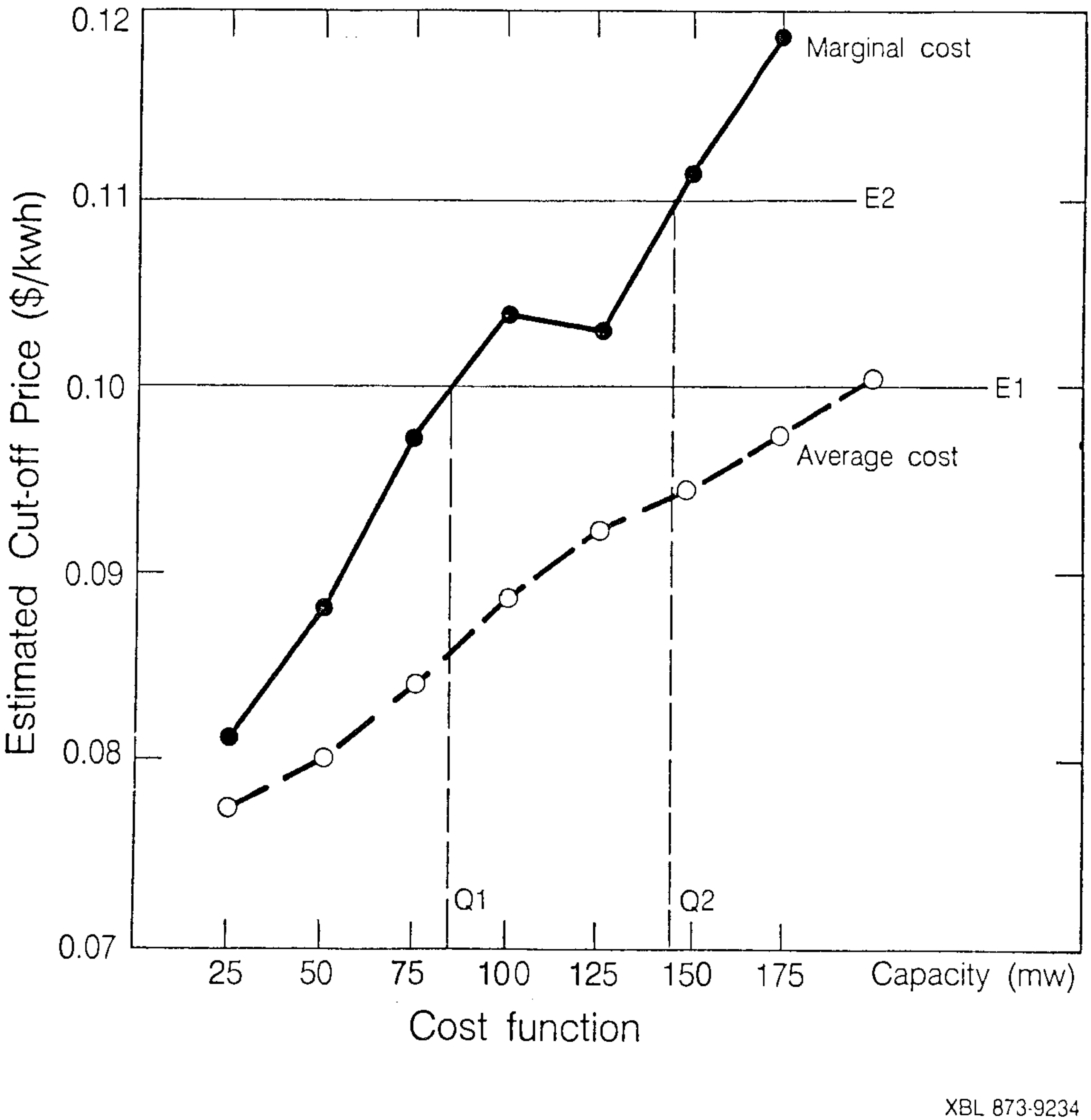

0.12
0.11
0.10
0.09
0.08
0.07
Estimated Cut-off Price ($/kwh)
Marginal cost
E2
E1
Average cost
Q1
Q2
25
50
75
100
125
150
175
Capacity (mw)
Cost function
XBL 873-9234

Figure 3.2

Given the sensitivity of the bidder's quantity offer to his cost structure, it is important to be able to characterize these functions if we want to have any ability to forecast the outcome of an auction. For this case study, we will focus attention exclusively on cogeneration. Although this is not the only technology being developed by QFs in California, it is the dominant one. The Table 3.1 estimates of 1995 QF development include gas-fired cogeneration projects at 56% of expected energy for the CEC projection and 61% for the SCE projection. In addition to this, a large fraction of the biomass-fuel projects are also cogeneration facilities.

To develop cost curves for power auctions in the 1990s, we must take some account of technical progress. The equipment currently used by natural gas-fired cogenerators can be expected to improve in efficiency in the future. To characterize these changes, it is convenient to distinguish between the gross and net electric heat rate of cogeneration systems (see for example Joskow and Jones [1983]). The gross heat rate is just the total fuel input divided by the total electrical output expressed in Btu/kWh. Because the output includes useful heat, we can convert this useful component into a "heat rate credit" that reduces the net amount of fuel required to produce power. For combustion turbines, this can amount to a reduction from a gross heat rate of over 12,000 Btu/kWh between 7,000 and 9,000 Btu/kWh (Merrill [1983]). By the 1990s, a newer, more efficient generation of gas turbines is expected to be available. General Electric will be delivering a gas turbine to Virginia Power in the late 1980s that is expected to have a gross heat rate of 10,340 Btu/kWh (Public Utilities Fortnightly, 1986). Other technical improvements are expected to result in net electric heat rates for gas-turbine cogenerators that approach 6,000 Btu/kWh (Larson and Williams [1985]).

To develop cost curves such as Figure 3.2, it is more convenient to consider the cogenerators' steam load explicitly rather than indirectly through the "net electric heat rate" concept. Industrial facilities' steam requirements vary. This variation can be represented by a steam load duration curve as in Figure 3.3. A minimum requirement that persists through the entire year, but higher steam loads last for fewer and fewer hours. For a given technology, some cogeneration capacity will produce just enough steam to meet the minimum steam load requirement. This capacity is designated C_{min} in Figure 3.3. As cogeneration capacity is increased to $C_{i,}$ there begin to be periods in which steam is produced that cannot be used. Average steam use nonetheless increases as capacity increases, but at a decreasing rate. Finally, some maximum is reached beyond which no additional steam can be used. For any particular choice of capacity $C_{i,}$ the net electric heat rate is calculated using the area under the steam load duration curve at that point. The choice of capacity, however, depends upon the relative value of steam and

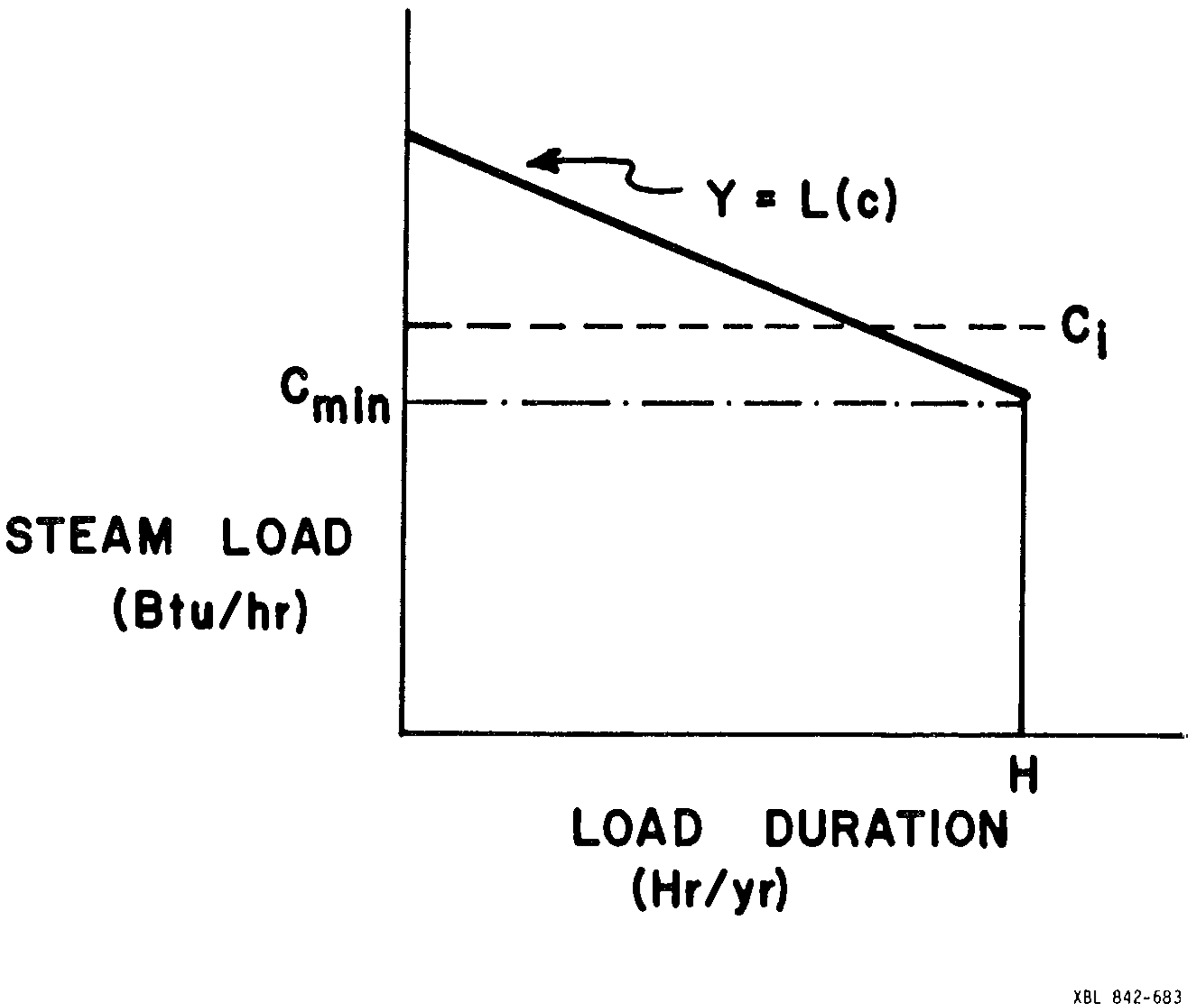


Figure 3.3 Steam load veruse

electricity.

The cost curve in Figure 3.2 is constructed assuming that an efficient gas turbine is used with a gross heat rate of 10,500 Btu/kWh. The steam load has a maximum average value of 150,000 lbs/hr which is reached at an electrical capacity of 75 MW. At 50-MW capacity this average falls to 130,000 lbs/hr, and at 25 MW, it falls to 80,000 lbs/hr. Net electric heat rates can be calculated from these data. These heat rates increase beyond 75 MW because there is no more use for the steam available, but overall fuel use is still increasing. The facility operates for 6,750 hours per year. The turbines exhibit capital cost scale economies up to 150 MW. These are represented using a scaling exponent of 0.802, which fits data on recent projects of this kind. There are no further scale economies beyond 150 MW. The annual fixed charge rate is assumed to be 15% for the projects that are 125 MW and below. To adjust for the risk of larger projects, we use higher fixed charge rates for larger capacity. These account for the increasing marginal costs of larger projects. Marginal costs increase due to higher net electric heat rates and the lack of further scale economies. The fixed charge rates represent minimum return requirements. The bidding strategy discussed below incorporates profit maximizing behavior. Marginal cost is just the change in total cost divided by the capacity increment. Table 3.3 exhibits the details of the cost structure for this case. Other cost functions are given in Appendix G; and some of these show scale economies absent from the example given here.

3.4 Exogenous Expectations Auction Model

In this section, we develop a procedure to simulate the outcome of a first-price auction that reflects both bidders' costs and expectations. We characterize classes of bidders parameterized by their cost functions as developed in Section 3.3 and their expectations about the outcome of the auction. Expectations are represented by a mean estimate of the cut-off price and a standard deviation around that mean estimate. These expectations are exogenous. Each class of bidders then performs an expected profit maximization calculation that determines the bid of that class. Given a set of bidders characterized in this manner and the corresponding set of bids that they produce, we can calculate the resultant cut-off price consistent with the costs, expectations and quantity to be purchased. The cut-off price may or may not be consistent with the expectations assumed. We explore a range of outcomes and measure the degree of "surprise" that results from different kinds of expectations among bidders.

We first summarize the bidder's strategy in Section 3.4.1 under the assumption that the decision to bid has been made. We comment on the role of this assumption. Next, in

QF Cost Function 1996 — No Scale Economies Above 150MW

Gas Turbines								
Capacity (MW)	175	150	125	100	75	50	25	5
Capital Cost ($M)	186	159	138	115	91	66	38	10
$/KW	1062	1062	1101	1151	1218	1320	1514	2082
Annual Charge Rate	0.17	0.16	0.15	0.15	0.15	0.15	0.15	0.15
Annual Charge ($M)	32	25	21	17	14	10	6	2
Hours	6750	6750	6750	6750	6750	6750	6750	6750
Heat Rate (Btu/kWh)	10500	10500	10500	10500	10500	10500	10500	12000
Fuel Cost ($/MMBtu)	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Annual Fuel Bill ($M)	98	84	70	56	42	28	14	3
Steam Load (MMBtu/hr)	150	150	150	150	150	130	80	20
Net Electric Heat Rate	9643	9500	9300	9000	8500	7900	7300	8000
Value of Steam	10	10	10	10	10	9	5	1
On-Site Electricity Credit								
Load (MW)	10	10	10	10	10	10	10	10
Value @ $12/MWh	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81
Unit Cost	0.1005	0.0974	0.0946	0.0925	0.0887	0.0842	0.0802	0.0776
Marginal Cost	0.1191	0.1117	0.1030	0.1040	0.0976	0.0882	0.0809	

Table 3.3

Section 3.4.2 we characterize the auction equilibrium that results from the assumed expectations. We do not analyze explicitly the process that generates these expectations, but we do measure the degree to which the auction outcome deviates from expectations. Finally, in Section 3.4.3 we describe results of our simulations.

3.4.1 Bidders' Strategy Given the Decision to Bid

We assume that bidders will maximize their expected profits. On a given bid of B, the expected profit is the difference between the bid and the bidder's average cost, AC, times the probability of winning. We assume that the uncertainty around the bidder's estimate of the cut-off price is distributed normally. We denote the cumulative normal distribution for a variate x with mean M and standard deviation SD by N(x,M,SD). The probability of winning with a bid B given an expected cut-off price of M and a standard deviation SD is given by the complement of the cumulative normal distribution up to B; i.e.

$$\text{Probability of Winning with B} = 1 - N((B,M,SD).$$

This is illustrated in Figure 3.4. Using this notation, the expected profit, E(B), on a bid B can be written as

$$E(B) = (B\text{-}AC)(1 - N((B),M,SD)).$$

The profit maximizing bid is found by setting $dE/dB = 0$ and solving for B.

This model is a decision-theoretic approach to the bidding problem which assumes that other bidders do not explicitly react to the strategy of an individual bidder. This general approach was first described by L. Friedman [1956] who characterized the probability of winning somewhat differently. The behavior of the other bidders in our approach is modeled indirectly by the exogenous specification of the expected cut-off price and its distribution. The formation of these expectations is not modeled, and neither is the decision to bid. Since both of these topics are important, some comment about them is appropriate.

In developing their own strategy, bidders must account for the actions of their potential competitors. The presence of competition affects strategy in two ways. First, the bidder may conclude that competition is so great that it is not productive even to bid. Second, once the bidder is committed, he must systematically adjust his bid (e.g. lower it) as the number of other bidders increases. The best study of these phenomena involves the data on oil lease auctions for the Outer Continental Shelf (Gilley and Karels [1981]). Naive statistical models of these data show the bid level positively related to the number of bidders. When the naive model is corrected for selection bias (i.e., accounting for the decision to bid), then the coefficient on the number of bidders in the bid level equation

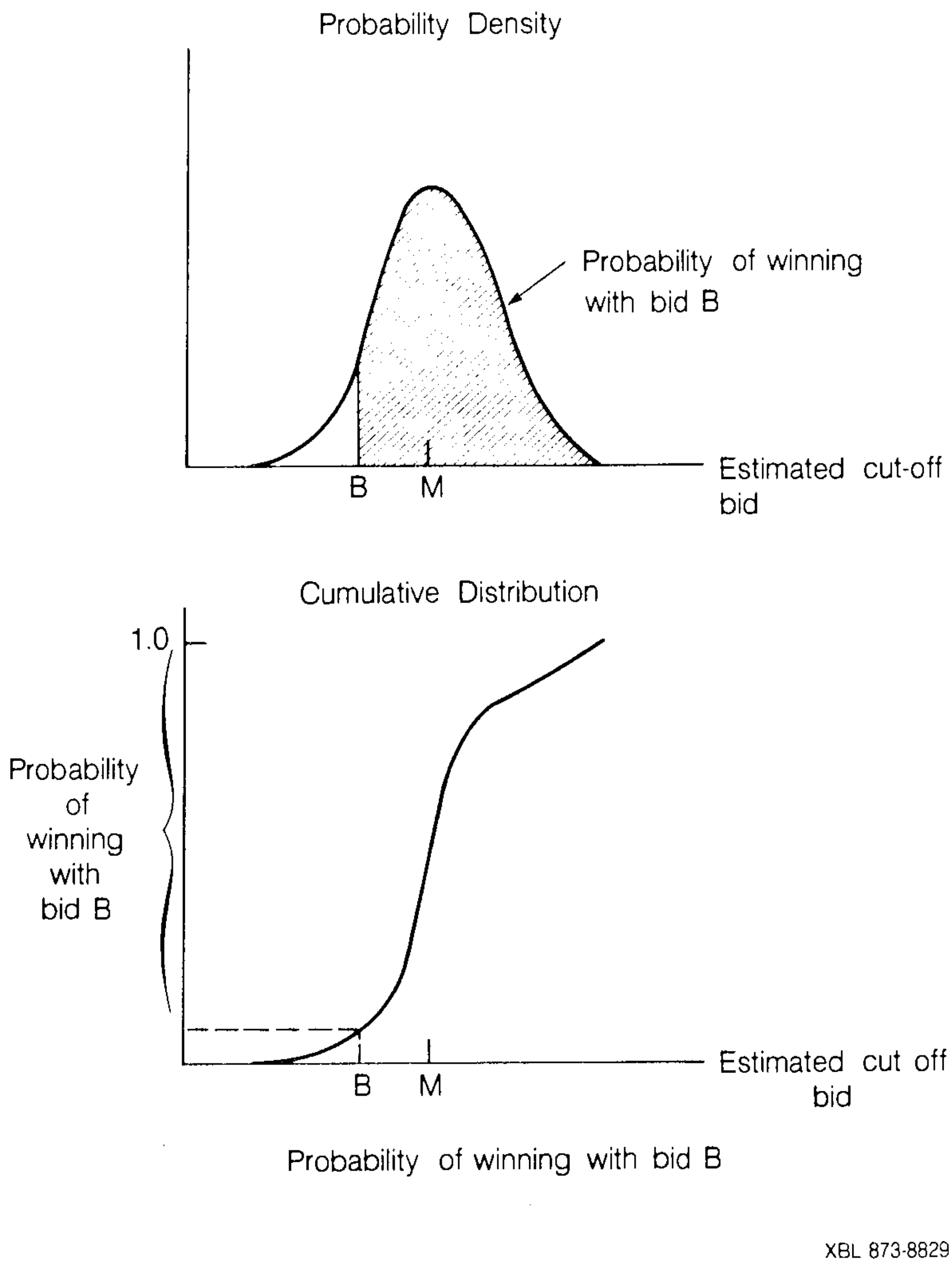

Probability Density
Probability of winning with bid B
B
M
Estimated cut-off bid
Cumulative Distribution
1.0
Probability of winning with bid B
B
M
Estimated cut off bid
Probability of winning with bid B
XBL 873-8829

Figure 3.4

becomes negative. The more sophisticated model corresponds to the intuition that bidders must bid less aggressively in the face of increasing competition.

There is a considerable controversy surrounding the question of whether the competitive adjustment is ever made completely. The oil lease context, among others, has given rise to the "winner's curse" problem. Petroleum engineers first observed that profits on off-shore drilling were subnormal because the winning bidder turned out to be the bidder with the most optimistic estimate of the true value of the tract (Capen, Clapp and Campbell [1971]). "Winner's curse" arises in auctions where the value of the object sold is similar, but unknown, for all bidders. In this situation, estimation differences have strongly influenced the outcome of the auction. Recently, this phenomenon has been studied in the laboratory. Kagel and Levin [1986] report experiments in which bidders' profits decline as the number of bidders increases. These results suggest that value estimates differ systematically among bidders and that adjustment for this effect is incomplete. This empirical literature suggests that expectations in our model ought to to treated with some generality.

We have not modeled the benefit of allowing multiple bids from a single bidder. It was argued in Sec. 2.4 that multiple bids will improve efficiency. The problem with simulating this effect is that it is difficult to specify the bidder's strategy function in this situation. With or without multiple bids, bidders will inevitably have market power.

3.4.2 Auction Summary Statistics

Using the bidder's strategy described in Section 3.4.1 and cost curves characterized in Section 3.3, we can generate price and quantity bids given bidder expectations. To provide the most flexible representation of the auction, we allow each bidder to have a different expected value for the cut-off price and a different variance. To calculate the actual cut-off price for a given situation, we must specify the acceptance rule. Because of the lumpiness problem, there is more than one possible rule. For simplicity, we focus attention on the two most extreme possible rules. Rule 1 requires the last bid to be rejected if the sum of the quantities offered including that bid exceed the IDR capacity. Rule 2 allows the last bid to be accepted as long as it fills any unfilled part of the IDR capacity requirement that has not been met by previous (i.e. lower priced) offers. In both cases, the cut-off price is the price of the last accepted bid.

Rule 3 treats the IDR capacity as strictly binding (as does Rule 1), but allows for searching past the rejected bidders to fill up the auction allotment. Rule 3 places a value of zero on capacity beyond the requirement. Rule 4 relaxes this last limitation by placing a value on excess quantities. As indicated in Section 3.7.3, this value is 8 cents/kWh for the next 200 MW beyond the 500-MW requirement. Under Rule 4, only the first marginal bidder has an opportunity to be accepted with excess quantities. If this bidder is rejected, the auction ends. Finally, Rule 5 uses the same valuation procedure for excess quantities as Rule 4, but the auction does not end if a marginal bidder is rejected. Evaluation under Rule 5 proceeds until a final bidder has been accepted or they have all been rejected.

To evaluate a particular outcome, it is useful to measure the degree to which expectations are consistent with what actually occurred. We calculate a quantity we call the "surprise" for this purpose. The surprise for a given bidder is the difference between the auction actual cut-off price and the bidder's estimate of the mean cut-off price divided by the bidder's estimate of the standard deviation of the cut-off price distribution. Dividing the difference between actual and expected cut-off prices by the bidder's standard deviation expresses the surprise in units of the bidder's own uncertainty. With this normalization, we can then characterize the average surprise of the auction as a whole.

We are also interested in the difference between the minimum social cost of power and the simulated auction outcome. We develop a number of indices to characterize and analyze this difference. The first index aggregates the individual bidder cost curves to produce a total supply curve, by the standard procedure for adding cost curves. For each simulated outcome, we calculate the difference between the total revenue paid by the utility (bid price times bid quantity summed over winning bidders) and minimum cost for the quantity purchased, normalized to that minimum cost. Because the total quantity purchased will vary depending on the acceptance rule, this first index will include deviations from the cost minimum that include lumpiness effects, as well as other factors.

We estimate some of the lumpiness cost in our second index by measuring the costs associated with fixing a desired quantity. The numerator of this index is the total revenue paid by the utility for the quantity purchased minus the minimum cost for 500 MW plus an adjustment term. This term is measured differently depending on whether the acceptance rule produces more or less than the desired 500-MW quantity. If the quantity accepted is less than 500, the adjustment term is the difference between 500 and the quantity accepted times the avoided cost. This is the cost of having no bidder for the remaining increment. If the quantity accepted is greater than 500, then we subtract the value of the additional increment; this is the avoided cost value beyond 500 times the quantity involved. The avoided cost beyond 500 is determined exogenously. The adjustment term in this case is a benefit to the degree that additional power has value. We normalize these deviations from the cost minimum to the social minimum cost measured at 500 MW. This is a different denominator from that of the first index, the minimum cost at the quantity accepted. This second index measures the costs associated with trying to buy only a fixed quantity of power.

Our third index measures the economic rent captured by bidders. This is calculated by multiplying the bidder's quantity by the difference between his bid and average cost and summing over all winning bids. We normalize the resulting quantity by the social cost minimum for the quantity accepted. This normalization allows a direct comparison with our first index. Such a comparison will indicate how much of the deviation from the cost minimum is due to bidders' rent capture. If this is a large fraction, then deviations from the social minimum are largely transfers and not inefficiencies.

Finally, we construct a narrow index of efficiency which measures the degree to which bidders are accepted due to estimating accuracy rather than low cost. One of Vickrey's original arguments in favor of second price auctions was that, under the conditions he assumed, bidders would be accepted in order of increasing cost. In first price auctions, superior estimation may change the cost ordering. We measure this effect by computing the minimum cost combination of bids for the quantity accepted in an auction given the quantities offered. In the event that this minimum requires divisibility of the last bid, we assume this is possible. The inefficiency index is the difference between the total cost of winning bids and this theoretical minimum, normalized to the theoretical minimum. This index measures inefficiencies of the kind Vickrey was concerned with as well as some inefficiencies due to lumpiness. However, if this index is zero, then there will be no Vickrey-type inefficiencies.

3.5 Results

We simulate a number of auctions, studying the efficiency of outcomes, the consistency of bidders' expectations, and the degree of competitiveness. We examine various methods for ameliorating the lumpiness problem in bid acceptance. We begin with acceptance rules that neglect the utility's demand curve for power. These will be tested under different combinations of bidders. We represent bidders by cost curves of the kind discussed in Section 3.3. All bidders are assumed to be natural gas fired cogenerators. They differ physically in the steam loads available to them, and in their expectations concerning competitive conditions.

We divide the bidders into two groups based on physical considerations. The first group we call the small bidders. Although their maximum steam loads vary by a factor of four (from 60,000 lbs/hr to 250,000 lbs/hr), their electrical cogeneration capacity falls within the range from 25-175 MW. Relative to the 500-MW capacity requirement, they are small. Under certain circumstances, these bidders would not offer enough capacity to fill the need increment. The second group has larger steam loads and, correspondingly, greater potential for electrical capacity. Based on a maximum steam load of 750,000 lbs/hr, such a bidder could offer 300 to 450 MW. Relative to the need increment, this is large. Detailed descriptions of the bidder cost functions are given in Appendix G.

We examine a few representative cases to develop intuition about the behavior of bidders and auction outcomes. We consider first a market without any large bidders. Tables 3.4 and 3.5 show cases where all four bidders have exactly the same expectations. These differ between the cases only in the mean. Table 3.4 shows a case in which each bidder expects the cutoff price to be $0.10, and Table 3.5 shows the same situation except that the bidder's expected value is $0.11. The change in quantity behavior between these cases is dramatic. With lower expected prices, the sum total of capacity is 300 MW, compared to the offer of 600 MW with higher expected prices. Bid strategy also changes, but not as much. With low prices, two of the four bidders bid at just about the expected value. This implies an anticipated probability of winning of about 50%. The less efficient bidders choose higher prices because their costs are greater. Bidder B makes the highest bid, implicitly accepting an ex ante probability of winning of about 22%. Bidder D, who is slightly more efficient, bids marginally lower, anticipating a 28% probability of success.

At higher expected prices, all bidders choose bids that increase their estimated chances of winning. The most efficient bidder (C) bids half a standard deviation below his expected cut-off price estimate. This implies a 69% chance of winning. Bidder A is the next most efficient. He bids 0.2 standard deviations below his estimated mean, implying a 58% chance of winning. Bidder D bids exactly at his expected value. Finally, the relatively inefficient Bidder B bids 0.1 standard deviations above the mean for a 46% chance of winning. In this case, however, the higher mean estimate produces so much greater a total quantity offered that competition is greater, and the higher ex-ante estimate of winning for Bidder B in this case does not result in his being accepted under most of our rules.

Estimation accuracy is measured by our "surprise" parameter. For each individual bidder, this is just the number of standard deviations by which his initial estimate of the cut-off price differs from the resultant cut-off price. It is interesting to aggregate this measure across bidders. We can think of each bidder's surprise as an estimation error. The root mean square (RMS) of the observed deviations is by definition the standard deviation of the estimation. Therefore, the RMS surprise ought to come out about equal to one on the average, over a large number of trials. If it is less than one, the bidders' estimation accuracy is better than they anticipate, and the opposite is true if it is greater

SYMBOLS EXPLANATION

for Tables 3.4 to 3.10

$$Surprise = \frac{Cut\text{-}off\ price - \mu_i}{\sigma_i}$$

$$Q_{tot} = \sum_{winners} Q_i$$

$$C_{tot} = \sum_{winners} [Q_i][Bid_i]$$

$$C_{\min} = \min_{\sum_{bidders} q_i = Q_{tot}} \left[\sum_{bidders} [AC_i(q_i)][q_i] \right]$$

$$C_{\min}^{AC} = \min_{\substack{bidders \\ AC_{i_1} < AC_{i_2} < \cdots < AC_{i_n} \\ \sum_{k=1}^{n-1} Q_{i_k} < Q_{tot} < \sum_{k=1}^{n} Q_{i_k}}} \left[\sum_{k=1}^{n-1} [Q_{i_k}][AC_{i_k}] + \left[Q_{tot} - \sum_{k=1}^{n-1} Q_{i_k} \right] [AC_{i_n}] \right]$$

$$I_1 = \frac{C_{tot} - C_{\min}}{C_{\min}}$$

$$I_2 = \frac{C_{tot} - C_{\min}(Q_{uti}) + |\ Q_{tot} - Q_{uti}\ |\ C_{uti}^{avoided}}{C_{\min}(Q_{uti})}$$

$$I_3 = \frac{\sum_{winners} [Bid_i - AC_i] Q_i}{C_{\min}}$$

$$I_4 = \frac{\sum_{winners} [Q_i][AC_i] - C_{\min}^{AC}}{C_{\min}^{AC}}$$

where

i is the index of the bidders

μ_i is bidder i's expectation of the unit cut-off price

σ_i is bidder i's standard deviation for that expectation

Q_i is the quantity offered by bidder i

$AC_i(q)$ is bidder i's average unit cost as a function of quantity

Bid_i is the unit price offered by bidder i

than one. Consistency of expectations can be measured by the degree to which the RMS surprise is closer to one in a given case.

By this standard, the expectations are more consistent in the case represented by Table 3.4 than the one represented by Table 3.5. In the cases shown in Table 3.4, the acceptance of Bidder B constitutes the unanticipated outcome. It is only because other bidders offer such small quantities that Bidder B is accepted. Conversely, the cases represented in Table 3.5 show unexpected accuracy. The cut-off price is anticipated correctly in almost all cases. The only deviation comes under Rule 2 which has the effect of accepting all bids. Even in this case, Bidder B has bid so close to his expected value that there is very little surprise on the average.

Table 3.4

PURPA PROJECT—OPTIMAL BID CALCULATIONS

Utility demand is 500 MW

Utility avoided cost is \$.12/kWh

There is 1 bidder of type a 0.10 0.01

There is 1 bidder of type b 0.10 0.01

There is 1 bidder of type c 0.10 0.01

There is 1 bidder of type d 0.10 0.01

OUTPUT SUMMARY										
Bidder	μ_i	σ_i	Q_i	AC_i	Bid	Surprise				
						Rule1	Rule2	Rule3	Rule4	Rule5
a 0.10 0.01	0.100	0.010	75.	0.089	0.100	0.810	0.810	0.810	0.810	0.810
b 0.10 0.01	0.100	0.010	25.	0.102	0.108	0.810	0.810	0.810	0.810	0.810
c 0.10 0.01	0.100	0.010	125.	0.087	0.099	0.810	0.810	0.810	0.810	0.810
d 0.10 0.01	0.100	0.010	75.	0.099	0.106	0.810	0.810	0.810	0.810	0.810

AUCTION SUMMARY										
	Cutoff price	Q_{tot}	R.M.S. surprise	Inefficiency						
				C_{tot}	C_{min}	C_{min}^{AC}	I_1	I_2	I_3	I_4
R1	0.108	300.	0.810	30.570	27.433	27.443	0.114	0.139	0.114	0.000
R2	0.108	300.	0.810	30.570	27.433	27.443	0.114	0.139	0.114	0.000
R3	0.108	300.	0.810	30.570	27.433	27.443	0.114	0.139	0.114	0.000
R4	0.108	300.	0.810	30.570	27.433	27.443	0.114	0.139	0.114	0.000
R5	0.108	300.	0.810	30.570	27.433	27.443	0.114	0.139	0.114	0.000

Table 3.5

PURPA PROJECT—OPTIMAL BID CALCULATIONS

Utility demand is 500 MW

Utility avoided cost is $.12/kWh

There is 1 bidder of type a 0.11 0.01

There is 1 bidder of type b 0.11 0.01

There is 1 bidder of type c 0.11 0.01

There is 1 bidder of type d 0.11 0.01

OUTPUT SUMMARY										
Bidder	μ_i	σ_i	Q_i	AC_i	Bid	Surprise				
						Rule1	Rule2	Rule3	Rule4	Rule5
a 0.11 0.01	0.110	0.010	150.	0.097	0.108	0.008	0.107	0.008	0.008	0.008
b 0.11 0.01	0.110	0.010	150.	0.104	0.111	0.008	0.107	0.008	0.008	0.008
c 0.11 0.01	0.110	0.010	150.	0.091	0.105	0.008	0.107	0.008	0.008	0.008
d 0.11 0.01	0.110	0.010	150.	0.101	0.110	0.008	0.107	0.008	0.008	0.008

AUCTION SUMMARY										
	Cutoff price	Q_{tot}	R.M.S. surprise	Inefficiency						
				C_{tot}	C_{min}	C_{min}^{AC}	I_1	I_2	I_3	I_4
R1	0.110	450.	0.008	48.496	42.730	43.440	0.135	0.138	0.118	0.000
R2	0.111	600.	0.107	65.157	59.002	59.010	0.104	0.193	0.104	0.000
R3	0.110	450.	0.008	48.496	42.730	43.440	0.135	0.138	0.118	0.000
R4	0.110	450.	0.008	48.496	42.730	43.440	0.135	0.138	0.118	0.000
R5	0.110	450.	0.008	48.496	42.730	43.440	0.135	0.138	0.118	0.000

When we consider the role of bigger bidders, the outcomes and possibilities become more complex. Table 3.6 summarizes a case in which two bidders with the cost conditions described as Type E compete with the two most efficient small bidders, A and C. Type E cost conditions represent the large enhanced oil recovery projects being developed in Kern County, California. One 300-MW project of this kind is already operating and several others are in the advanced development stage. Projections of the ultimate potential from this resource run as high as 6,000 MW (Williams [1985]). Type E projects could also be constructed at large oil refineries or chemical plants. There are also projects of this magnitude being developed in these industries.

Table 3.6

PURPA PROJECT—OPTIMAL BID CALCULATIONS

Utility demand is 500 MW

Utility avoided cost is \$.12/kWh

There is 1 bidder of type a 0.10 0.01

There is 1 bidder of type c 0.10 0.01

There is 1 bidder of type e 0.08 0.01

There is 1 bidder of type e 0.11 0.01

OUTPUT SUMMARY										
Bidder	μ_i	σ_i	Q_i	AC_i	Bid	Surprise				
						Rule1	Rule2	Rule3	Rule4	Rule5
a 0.10 0.01	0.100	0.010	75.	0.089	0.100	0.017	0.314	0.017	0.017	0.017
c 0.10 0.01	0.100	0.010	125.	0.087	0.099	0.017	0.314	0.017	0.017	0.017
e 0.08 0.01	0.080	0.010	250.	0.082	0.089	2.017	2.314	2.017	2.017	2.017
e 0.11 0.01	0.110	0.010	325.	0.084	0.103	-0.983	-0.686	-0.983	-0.983	-0.983

AUCTION SUMMARY										
	Cutoff price	Q_{tot}	R.M.S. surprise	Inefficiency						
				C_{tot}	C_{min}	C_{min}^{AC}	I_1	I_2	I_3	I_4
R1	0.100	450.	1.122	42.223	37.565	37.565	0.124	0.166	0.113	0.011
R2	0.103	775.	1.227	75.744	64.333	65.200	0.177	0.318	0.164	0.000
R3	0.100	450.	1.122	42.223	37.565	37.565	0.124	0.166	0.113	0.011
R4	0.100	450.	1.122	42.223	37.565	37.565	0.124	0.166	0.113	0.011
R5	0.100	450.	1.122	42.223	37.565	37.565	0.124	0.166	0.113	0.011

We give the Type E bidders substantially different expected values for the cut-off price. The pessimistic bidder, who anticipates a cut-off price of \$0.08, offers 250 MW. This pessimist bids 0.9 standard deviations above his estimate, anticipating only an 18% chance of winning. The optimist bids 0.7 standard deviations below his mean, anticipating a 75% chance of winning. Both bidders turn out to be wrong by a fair amount. Under every rule except Rule 2, the optimistic bidder is rejected. Both bidders show large surprise values, particularly the pessimist. The auction as a whole shows greater than average surprise, the RMS being in the range of 1.1-1.2.

The acceptance rules beyond Rule 1 and Rule 2 do not show any interesting results in this case because the lumpiness is so extreme. Rule 3 is the weakest of them all. It places no value on power beyond 500 MW. Rules 4 and 5 value the next 200 MW at \$0.08 and beyond that at \$0.07. The optimistic big bidder is too large and his bid is too high to benefit from these values. We can easily show this. The value of this bidder's capacity is \$0.12 for the first 50 MW, \$0.08 for the next 200 MW and \$0.07 for the last 75 MW. The weighted average of these values is \$0.0838 compared to his bid of \$0.103. Therefore, it is cheaper for the utility to produce power beyond 450 MW itself than to purchase from this supplier at his quoted price.

This case does produce some Vickrey-type inefficiency because the rejected large bidder is actually a lower cost producer than the two smaller bidders who are accepted in all cases. Our index of this type of inefficiency shows a rather small value for this effect, namely about 1%. In general, we do not expect this type of inefficiency to be large. The reason for this can be understood by comparing the inefficiency with the economic rent term. The cost differences among bidders are relatively small compared to the average spread between the cost and the bid of each bidder. This means that much more of the deviation between utility cost and the social cost minimum is due to economic rent than to Vickrey-type inefficiency.

Because so much of the argument in favor of second-price auctions hinges on the possibility of Vickrey-type inefficiencies, we try to construct some cases in which the values of I_4 are greater than in Table 3.6. Table 3.7 is a slight variation of Table 3.6 where both E-type bidders expect an 11-cent cut-off price. This causes them both to bid above the small, less efficient projects. Under Rule 1 they are rejected and only 200 MW is accepted. In this unlikely case, I_4 is 4.4%. The inefficiency here is caused as much by the acceptance rule as anything else. Under all other rules in this situation, I_4 is 1.7%.

Table 3.8 is based on the same cast of characters. This time the large bidders are divided into an optimist and a pessimist as in Table 3.6. The smaller bidders have different expectations this time. As in Tables 3.6 and 3.7, we get inefficiency under Rule 1. What differs here is that it gets larger (from 1.4-2.6%) under Rules 3 and 5. These differences are due to the acceptance of Bidder C whose average cost is 9.1 cents compared to the rejected Bidder E with average cost of 8.4 cents. It is greater in Table 3.8 than Table 3.6 because Bidder C's expectations made him choose a higher cost configuration.

Table 3.9 is one more variation of the same theme. In this case, the E-type bidder who estimates low is not as low as before. Therefore, his quantity offered is greater (300 MW vs. 250 MW), leaving less room for other bidders. I_4 takes its highest value under Rule 5 where valuing excess quantities allows acceptance of the small bidders ahead of the more efficient large bidder. I_4 in this case is 3.3%.

It might be argued that the presence of two E-type bidders distorts these cases, and that I_4 would be greater without them. Table 3.10 involves only one E-type bidder and the bidder set from Table 3.4, including their expectations. Here we have a case of I_4 at

3.1% under Rule 3. The inefficiency again is due to lumpiness effects interacting with the acceptance rule. Because no value is given to excess quantities, Bidder C is rejected. Accepting C would mean taking 525 MW, 25 MW over the limit. Instead the less efficient Bidders B and D are accepted under Rule 3. As Table 3.10 shows, however, once excess quantities are appropriately valued Bidder C will be accepted and B and D will be rejected. Under Rules 4 and 5, I_4 is zero.

Table 3.7

PURPA PROJECT—OPTIMAL BID CALCULATIONS

Utility demand is 500 MW

Utility avoided cost is $.12/kWh

There is 1 bidder of type e 0.11 0.01

There is 1 bidder of type e 0.11 0.01

There is 1 bidder of type c 0.10 0.01

There is 1 bidder of type a 0.10 0.01

OUTPUT SUMMARY										
Bidder	μ_i	σ_i	Q_i	AC_i	Bid	Surprise				
						Rule1	Rule2	Rule3	Rule4	Rule5
e 0.11 0.01	0.110	0.010	325.	0.084	0.103	-0.983	-0.686	-0.686	-0.686	-0.686
e 0.11 0.01	0.110	0.010	325.	0.084	0.103	-0.983	-0.686	-0.686	-0.686	-0.686
c 0.10 0.01	0.100	0.010	125.	0.087	0.099	0.017	0.314	0.314	0.314	0.314
a 0.10 0.01	0.100	0.010	75.	0.089	0.100	0.017	0.314	0.314	0.314	0.314

AUCTION SUMMARY										
	Cutoff price	Q_{tot}	R.M.S. surprise	Inefficiency						
				C_{tot}	C_{min}	C_{min}^{AC}	I_1	I_2	I_3	I_4
R1	0.100	200.	0.696	19.909	16.683	16.760	0.193	0.352	0.145	0.044
R2	0.103	525.	0.533	53.430	43.188	43.995	0.237	0.244	0.202	0.017
R3	0.103	525.	0.533	53.430	43.188	43.995	0.237	0.244	0.202	0.017
R4	0.103	525.	0.533	53.430	43.188	43.995	0.237	0.244	0.202	0.017
R5	0.103	525.	0.533	53.430	43.188	43.995	0.237	0.244	0.202	0.017

Table 3.8

PURPA PROJECT—OPTIMAL BID CALCULATIONS

Utility demand is 500 MW

Utility avoided cost is $.12/kWh

There is 1 bidder of type e 0.08 0.01

There is 1 bidder of type e 0.11 0.01

There is 1 bidder of type c 0.11 0.01

There is 1 bidder of type a 0.10 0.01

OUTPUT SUMMARY										
Bidder	μ_i	σ_i	Q_i	AC_i	Bid	Surprise				
						Rule1	Rule2	Rule3	Rule4	Rule5
e 0.08 0.01	0.080	0.010	250.	0.082	0.089	2.017	2.314	2.512	2.017	2.512
e 0.11 0.01	0.110	0.010	325.	0.084	0.103	-0.983	-0.686	-0.488	-0.983	-0.488
c 0.11 0.01	0.110	0.010	150.	0.091	0.105	-0.983	-0.686	-0.488	-0.983	-0.488
a 0.10 0.01	0.100	0.010	75.	0.089	0.100	0.017	0.314	0.512	0.017	0.512

AUCTION SUMMARY										
	Cutoff price	Q_{tot}	R.M.S. surprise	Inefficiency						
				C_{tot}	C_{min}	C_{min}^{AC}	I_1	I_2	I_3	I_4
R1	0.100	325.	1.225	29.826	26.665	26.760	0.119	0.229	0.101	0.014
R2	0.103	650.	1.264	63.347	53.528	54.363	0.183	0.242	0.168	0.000
R3	0.105	475.	1.328	45.595	39.745	39.745	0.147	0.175	0.122	0.026
R4	0.100	325.	1.225	29.826	26.665	26.760	0.119	0.229	0.101	0.014
R5	0.105	475.	1.328	45.595	39.745	39.745	0.147	0.175	0.122	0.026

Table 3.9

PURPA PROJECT—OPTIMAL BID CALCULATIONS

Utility demand is 500 MW

Utility avoided cost is \$.12/kWh

There is 1 bidder of type e 0.09 0.01

There is 1 bidder of type e 0.11 0.01

There is 1 bidder of type c 0.11 0.01

There is 1 bidder of type a 0.10 0.01

OUTPUT SUMMARY										
Bidder	μ_i	σ_i	Q_i	AC_i	Bid	Surprise				
						Rule1	Rule2	Rule3	Rule4	Rule5
e 0.09 0.01	0.090	0.010	300.	0.082	0.092	0.017	1.314	0.017	0.017	1.512
e 0.11 0.01	0.110	0.010	325.	0.084	0.103	-0.983	-0.686	-0.983	-0.983	-0.488
c 0.11 0.01	0.100	0.010	150.	0.091	0.105	-0.983	-0.686	-0.983	-0.983	-0.488
a 0.10 0.01	0.100	0.010	75.	0.089	0.100	0.017	0.314	0.017	0.017	0.512

AUCTION SUMMARY										
	Cutoff price	Q_{tot}	R.M.S. surprise	Inefficiency						
				C_{tot}	C_{min}	C_{min}^{AC}	I_1	I_2	I_3	I_4
R1	0.100	375.	0.861	35.182	31.025	31.025	0.134	0.214	0.125	0.009
R2	0.103	700.	0.832	68.702	57.680	58.548	0.191	0.275	0.176	0.000
R3	0.100	375.	0.861	35.182	31.025	31.025	0.134	0.214	0.125	0.009
R4	0.100	375.	0.861	35.182	31.025	31.025	0.134	0.214	0.125	0.009
R5	0.105	525.	0.870	50.950	43.188	43.515	0.180	0.184	0.139	0.033

Table 3.10

PURPA PROJECT—OPTIMAL BID CALCULATIONS

Utility demand is 500 MW

Utility avoided cost is $.12/kWh

There is 1 bidder of type a 0.095 0.01

There is 1 bidder of type b 0.10 0.01

There is 1 bidder of type c 0.10 0.01

There is 1 bidder of type d 0.10 0.01

There is 1 bidder of type e 0.10 0.01

OUTPUT SUMMARY										
Bidder	μ_i	σ_i	Q_i	AC_i	Bid	Surprise				
						Rule1	Rule2	Rule3	Rule4	Rule5
a 0.095 0.01	0.095	0.010	75.	0.089	0.098	0.318	0.417	1.310	0.417	0.417
b 0.10 0.01	0.100	0.010	25.	0.102	0.108	-0.182	-0.083	0.810	-0.083	-0.083
c 0.10 0.01	0.100	0.010	125.	0.087	0.099	-0.182	-0.083	0.810	-0.083	-0.083
d 0.10 0.01	0.100	0.010	75.	0.099	0.106	-0.182	-0.083	0.810	-0.083	-0.083
e 0.10 0.01	0.100	0.010	325.	0.084	0.098	-0.182	-0.083	0.810	-0.083	-0.083

AUCTION SUMMARY										
	Cutoff price	Q_{tot}	R.M.S. surprise	Inefficiency						
				C_{tot}	C_{min}	C_{min}^{AC}	I_1	I_2	I_3	I_4
R1	0.098	400.	0.216	39.273	33.020	33.737	0.189	0.217	0.163	0.004
R2	0.099	525.	0.201	51.669	44.622	44.725	0.158	0.178	0.156	0.000
R3	0.108	500.	0.932	49.934	42.147	42.508	0.185	0.185	0.145	0.031
R4	0.099	525.	0.201	51.669	44.622	44.725	0.158	0.178	0.156	0.000
R5	0.099	525.	0.201	51.669	44.622	44.725	0.158	0.178	0.156	0.000

The cases summarized in these tables show inefficiencies in first-price auctions that are relatively small. It is reasonable to ask if this result is general. We believe that it is, at least when near-marginal bidders face increasing marginal costs. Significant inefficiency will result only if the price expectations of bidders show large differences and the bidder's cost differences are also large. In this case, a low estimator can force out a low-cost producer who is a high estimator. This situation is relatively unlikely to occur because there is an equilibrating effect that links expectations and costs through capacity choice. The inefficient outcome occurs if a low-cost producer bids too high to be accepted. This is relatively unlikely because such a producer would increase his capacity if he thought that the cut-off price would be high. The additional capacity has higher cost, thus raising the bidder's average cost. This means that even if he were rejected, the inefficiency of not selecting him is not too great because his cost is not too low anymore. The tendency toward equilibrium occurs because it is inconsistent to expect a high cut-off price, but choose a low capacity and, therefore, a low cost.

This result follows from our representation of the bidder's choice of capacity given a cost curve. Capacity is chosen where marginal cost equals expected cut-off price.

It is incorrect to measure efficiency effects from bidder's cost curves. We can only measure these effects given choices of capacity based on price expectations. In fact, expectations can result in a bidder with a "low" cost curve offering a project that is sized with an average cost that is higher than that of another bidder with a "high" cost curve. All that is necessary is that the first bidder expect a substantially higher price than the second. In Appendix I, we present a particular example that illustrates this phenomenon.

Thus, potential inefficiencies will be mitigated by expectations that reduce cost differences among bidders. This mitigation is not considered in the theoretical literature on auctions. The result of this mitigation is to reduce the weight one might give to theoretical advantages of second-price auctions. The cost equilibration effect is completely independent of the subsequent negotiations effect described in Section 2.2, which also casts doubt on the superiority of the second-price mechanism.

We expect that these results will be reasonably generic. The deviation of utility cost from the social minimum ranges from 10 to 20%. The largest part of this is transfers in the form of economic rent to the bidders. Estimation problems will occasionally result in some less efficient bidders being accepted and more efficient ones rejected, but the magnitude of this effect will be small. The cost of fixing a firm limit on the capacity to be purchased is not small. This is most clearly seen in our second index evaluated under Acceptance Rule 2. Rule 2 allows lumpy marginal bidders to be accepted, but Index 2 emphasizes the value of hitting the need increment precisely. When Rules 4 and 5 change the acceptance procedure, then the value of Index 2 will go down.

IV. CONCLUSIONS AND RECOMMENDATIONS FOR PURPA AUCTIONS

This section briefly states the main conclusions and recommendations made in this report. These cover the four main concerns of the report: the general form of the auction, dealing with the discrete nature of bid quantities, dealing with non-price aspects of bids, and auction frequency.

With respect to the overall auction form, we recommend standard (i.e., first-price, discriminatory) sealed bidding. We do so because it is familiar, relatively collusion resistant, appropriate for large, complex transactions, and because the economic theory suggesting that sealed second-price (nondiscriminatory) auctions are more efficient clearly does not apply. It does not take account of the facts that in PURPA auctions there will be subsequent negotiations with third parties and that a single bidder or economic interest may offer several blocks of capacity.

As we have noted, the choice of the rule to use in deciding which bids to accept is not straightforward. Most generally, we recommend that in advance of the auction there be an explicit, thoughtful determination of the rule that will be used. More particularly, we recommend that a rule be adopted that accepts bids in order of increasing cost per kWh subject to several measures to reduce the impact of the discrete nature of the bids. The measures we favor include encouraging multiple bids (for incremental quantities) by a bidder, allowing a reasonable tolerance in the definition of the required quantity, valuing excess power beyond the desired quantity at avoided cost in deciding if a marginal bid is acceptable, and allowing a marginal bidder who offers too large a quantity the option of reducing that quantity.

We recommend that non-price factors be included in bid evaluation only in ways that reflect costs. We conclude that bidder incentives and postsale negotiations will tend to narrow the difference between different schemes for dealing with non-price features of bids. We also conclude that there is probably not one best approach nationally for dealing with non-price features.

Finally, we recommend that bidders hold auctions every few years if they need capacity but not much more frequently because, if auctions are too frequent, collusion is made easier, large projects are disadvantaged and the calculation of true avoided cost may become more difficult because it will tend to depend upon the outcome of future auctions. On the other hand, if auctions are too infrequent, promising potential cogeneration projects may be missed.

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LIST OF APPENDICES

Appendix A

The Effect of Revealed Second-Price Auction Procedures in Models with Subsequent Partial Rent Capture

We consider a simple model of a low-bid-wins second-price auction in which the winning bidder must subsequently negotiate with third parties such as labor unions or permitting authorities. We assume that the third parties have some market power and that in addition to whatever else they may charge, they also extract some fraction of the economic rent the winning bidder revealed by the difference between his winning bid and the amount he must pay under the second-price procedure. In our model, the bidders' equilibrium bidding strategies take account of the effect of their bids on the winner's subsequent negotiations.

One result in our model is that the expected profit received by the winning bidder is independent of the amount of revealed economic rent captured by third parties. Therefore, all of the third-party rent capture payments come from the bid taker. This result is not restricted to our simple model but can be derived much more generally from a revenue equivalence theorem of Myerson (1981). Third-party rent capture payments can be substantial. Use of a procedure that does not reveal the economic rent and thus prevents a fraction of them from being captured will benefit the bid taker.

This appendix describes the simple model and its solution. It then discusses these results and the types of auction procedures they suggest.

The Model

The model we use is extremely simplified. We assume a low bid wins auction with two bidders. Each bidder independently and privately learns his exact basic cost should he win the auction. *A priori*, the cost is equally likely to take on any value from 0 to 1. Each bidder then uses a strategy for his bid that depends upon his basic cost but not upon the still unrevealed cost of his competitor. The auction is a second-price auction that awards the contract to the low bidder at the price of the higher bid. However, third parties with whom the winner must negotiate learn of the difference between the low bid and the second bid and are able to extract some fraction, α, of this difference from the winner. The bidders know that this will happen and allow for it in their bids. We assume that each bidder is risk neutral and, thus, chooses his bid to maximize his expected profit from the auction. We seek a symmetric set of equilibrium strategies. In such an equilibrium, neither bidder can unilaterally improve his expected profit.

Mathematically, we have basic cost c_i, $i = 1, 2$ for the two bidders. It is uniformly and independently distributed on [0,1]. Bidders follow strategies $b_i(c_i)$, $i = 1, 2$, that are increasing functions of c_i with inverse functions $b_i^{-1}(.)$ When bidder i has cost c_i, his expected profit is given by

$$E[\pi_i(c_i)] = \int_{b_j^{-1}(b_i(c_i))}^{1} [b_j(c_j) - \alpha\,(b_j(c_j) - b_i(c_i)) - c_i]\; f\,(c_j)dc_j,\; i,j{=}1,2;\, j{\neq}i.$$

In this expression, the square brackets contain bidder i's profit if he wins with a bid of b_i when bidder j's bid is $b_j(c_j)$. The quantity $f(c_j)$ is the uniform probability density that bidder j has cost c_j. It is 1 on the interval [0,1]. The integral is over those values of c_j that will lead to bidder i winning.

The Model's Solution

The derivative of $E[\pi_i(c_i)]$ with respect to b_i is given by

$$\frac{dE[\pi_i(c_i)]}{db_i} = \int_{b_j^{-1}(b_i(c_i))}^{1} \alpha f(c_j)\alpha c_j - [b_j(b_j^{-1}(b_i)) - \alpha(b_j(b_j^{-1}(b_i)) - b_i(c_i)) - c_i]\, f(b_j^{-1}(b_i))\frac{db_j^{-1}(b_i)}{db_i},$$

$$i,j = 1,2; i \neq j.$$

Setting this derivative equal to zero for $i = 1$ and $i = 2$, using the symmetry condition

$$b_1(c_1) = b_2(c_2) \equiv b(c),$$

and the relationships

$$b_j^{-1}\,(b_i(c_i)) = c_i,\; i = 1,2,$$

and

$$\frac{db_j^{-1}(b_i(c_i))}{db_i} = \frac{1}{b_i'(c_i)},\; i = 1,2,$$

and simplifying gives the differential equation that a symmetric equilibrium strategy $b(c)$ must satisfy:

$$\alpha(1-c)b'(c) = b(c) - c.$$

It may be verified that the solution of this equation is

$$b(c) = \frac{\alpha + c}{\alpha + 1}.$$

When both bidders follow this strategy, a bidder whose cost is c has an expected profit

$$E(\pi(c)) = (1-c)^2/2.$$

This quantity is independent of α.

A priori, before learning his cost, each bidder has a 50% chance of winning and an expected profit, independent of α, of

$$\int_0^1 \frac{(1-c)^2}{2} f(c)dc = 1/6.$$

The expected cost of the lower cost bidder is one third. When $\alpha = 0$, the expected payment of the bid taker is $1/3 + 2(1/6) = 2/3$.

With equilibrium bidding, the expected value of the higher bid is $(3\alpha + 2)/(3\alpha + 3)$, and the expected value of the lower bid is $(3\alpha + 1)/(3\alpha + 3)$. The expected difference between the bids is $1/(3\alpha + 3)$, and the expected payment to the third parties is α times this amount: $\alpha/(3\alpha + 3)$. As a fraction of the cost to the bid taker when $\alpha = 0$, this cost is $\alpha/(3\alpha + 3) \div 2/3 = \alpha/(2\alpha + 2)$. Thus, if third parties can extract 10% of the difference between the bids, the extra cost to the bid taker is 4.5%. If they can extract half the difference, the extra cost is 16 2/3%; and if they can extract it all, the cost is 25%.

Discussion

When a bidder is being paid an amount beyond a bid he was willing to accept and this amount is known publicly, others with whom he must deal will have knowledge of this surplus and, knowing of it, may be able to obtain some part of it that in the absence of such knowledge they could not obtain. If so, then a bidder has an incentive to take this into account in his bid. In the simple model just derived, and in a wide class of other models, all of the added cost is passed on to the bid taker. Thus, the bid taker has an incentive to avoid such a situation. The bid taker can do this by using a first price auction. This is equivalent to setting $\alpha = 1$, but letting the bid taker himself be the "third party".

Another possibility is for the bid taker attempt to keep the difference between bids secret from everyone except the winning bidder. If he is successful, then no one can take advantage of knowledge of the difference. However, there are possible problems with this approach. It may be difficult or costly to do. Keeping the required information secret may interfere with one of the purposes of using an auction--assuring everyone that the bidder selection process was fair and honest. Finally, merely keeping the information secret is insufficient; the bidders must be absolutely sure, in advance, that the secret will be kept. If they aren't, they may bid as if some rent will be extracted, and the bid taker will lose out.

A final possibility is using an oral progressive bid format so that the winning bidder need reveal no more than that his cost is below that of the other bidder. This avoids the problem of revealed rent but creates other problems. In particular, collusion among bidders is stable in such procedures but not in sealed procedures.

Appendix B

A Simple Bidding Model

This Appendix analyzes a situation in which a bidder submits a bid, b_1, for a job or contract of known cost c, to himself. To simplify the analysis, we assume that the bidder believes the best competitive bid is distributed uniformly on the interval (a,b), where $c \leq b_1 \leq b$ and $a \leq c$ (or at least below the value we will calculate for the optimum bid).

In this case, the bidder's expected profit $E(b_1)$ is $b_1 - c$, times the probability he wins, $(b-b_1)/(b-a)$. Thus,

$$E(b_1) = (b-b_1)(b_1-c)/(b-a). \tag{1}$$

Setting $dE/db_1=0$ and solving for b_1 gives the optimal bid b_1^*:

$$b_1^* = (b+c)/2. \tag{2}$$

The bidder's maximized expected profit is

$$E\,(b_1^*) = (b-c)^2/4(b-a). \tag{3}$$

Appendix C

Solving the Knapsack Problem and a Variant of It

This appendix defines two mathematical problems that may arise in making bid acceptance decisions and describes how they can be solved. One of these problems is called the "knapsack problem." There is an extensive literature on it and extensions of it. See for example, Bradley, Greeberg and Hegerich, Kolesar, and Magazine et al. It is discussed in some standard texts on operations research such as Wagner.

The other problem is a variant of the knapsack problem. While it is not widely discussed, some of the methods used to solve the knapsack problem can be used to solve it.

The knapsack problem gets its name from the problem faced by a hiker who has a knapsack that holds a limited volume and who has a selection of potential items to take with him, each of which has a known value to him and a known volume. His problem is to take the most valuable set of items subject to the constraint that their total volume cannot exceed the capacity of his knapsack. Because fractional items cannot be taken, the problem cannot be solved in general by rank ordering the items in order of value per unit volume and taking lower and lower ranked items until the knapsack volume constraint is met. Hence, the "lumpiness" of knapsack packing is analogous to that of the bid acceptance problem.

The bid acceptance decision that is closest to the knapsack problem can be stated as:

Problem 1

$$\text{Maximize} \sum_{i=1}^{n} (C-c_i)q_i x_i$$

$$\text{Subject} \sum_{i=1}^{n} q_i x_i \leq Q$$

$$x_i = 0 \text{ or } 1,\ i = 1,2,\ldots,n.$$

In this statement, C is the utility's avoided cost per kWh, Q is its quantity requirement, c_i is the cost per kWh of bid i and q_i is the quantity it offers. Setting $x_i = 1$ signifies a decision to accept bid i. The objective function is the cost saving of the utility, and the constraint guarantees that the required capacity will not be exceeded.

The generalized version of this problem occurs when the absolute requirement given in the inequality constraint in Problem 1 is replaced by a more general function for giving value to power supplied, $V(q)$.

This relaxation gives rise to

Problem 2

$$\text{Maximize} \quad V\left(\sum_{i=1}^{n} q_i x_i\right) - \sum_{i=1}^{n} c_i q_i x_i$$

Subject $x_i = 0$ or 1, $i = 1,2,\ldots,n$.

If $V(q)$ is given by

$$V(q) = \begin{cases} Cq, & 0 \le q \le Q \\ 0, & \text{otherwise} \end{cases}$$

(and if $q_i \ge 0$ for all bids), then Problem 2 is equivalent to Problem 1. In general, $V(q)$ can be viewed as the integral of the utility's demand curve for power.

There are 2^n possible bid acceptance decisions. If there are only a few bids, say five, Problem 2 can be solved by enumeration. However, when there are 20 bids, 2^{20} is over a million. Hence, methods other than enumeration are needed when the number of bids is large. One method that can be used is dynamic programming. To use it, we define and recursively evaluate the following function:

$F_i(q) \equiv$ the maximum value achievable in the objective function of problem 2 where variables $x_i, x_2, \ldots, s_i$ have been selected in such a way that $\sum_{j=1}^{i} q_j x_j = q$.

The recursion we use is

$$F_i(q) = \text{Max} \begin{Bmatrix} F_{i+1}(q) \\ F_{i+1}(q+q_i) - c_i q_i \end{Bmatrix} \quad i=0,1,\ldots,n-1.$$

$$F_n(q) = V(q).$$

In the recursion, choosing the first quantity in the maximization choice corresponds to setting x_{i+1} equal to 0 and choosing the second to setting it to 1.

Appendix D

Optimal Bidding When a Single Price and Quantity Must be Offered

This Appendix considers the problem faced by a bidder who wishes to maximize his expected profit in a first-price auction in which he may offer a single quantity of his choosing at a price of his choosing. We develop optimality conditions for his bid that generalize the well known [e.g. see Friedman, 1956] conditions for an optimal bid when quantity is fixed and only the price to be offered is at issue. We then discuss these conditions and specialize them.

<u>Notation</u>

P	= unit price offered
Q	= quantity offered
C(Q)	= total cost to the bidder of quantity Q
Pr(P,Q)	= the bidder's assessed probability of having his offer accepted as a function of P and Q
E(P,Q)	= The bidder's expected profit if he offers quantity Q at unit price P

With this notation, the bidder's expected profit is given by

$$E(P,Q) = Pr(P,Q)[PQ - C(Q)], \tag{1}$$

and its partial derivatives by

$$\frac{\partial E(P,Q)}{\partial P} = \frac{\partial Pr(P,Q)}{\partial P}\left[PQ - C(Q)\right] + Pr(P,Q)Q \tag{2}$$

and

$$\frac{\partial E(P,Q)}{\partial P} = \frac{\partial Pr(P,Q)}{\partial Q}\left[PQ - C(Q)\right] + Pr(P,Q)\left[P - \frac{dC(q)}{dQ}\right] \tag{3}$$

Setting these partial derivatives equal to 0 gives the first order optimality conditions:

$$P = \frac{C(Q)}{Q} - \frac{Pr(P,Q)}{\partial Pr(P,Q)/\partial P} \tag{4}$$

and

$$\frac{dC(Q)}{dQ} = P + \left[PQ - C(Q)\right]\frac{\partial Pr(P,Q)/\partial Q}{Pr(P,Q)} \quad . \tag{5}$$

In discussing these, it will be useful to note that C(Q)/Q is average unit cost, and dC(Q)/dQ is marginal unit cost and in the range of interest will normally be an increasing function of Q. The quantity $\partial Pr(P,Q)/\partial P$ is the rate of change in the probability of winning with respect to change in price; it will be negative. The quantity $\partial Pr(P,Q)/\partial Q$ is the rate of change in the probability of winning as the quantity offered is changed.

For a given value of Q, condition (4) is the well known formula for optimal bid price. The optimal price is just the average cost plus a premium which is the ratio of the probability of winning at the optimum price to the rate of decrease in that probability at that price.

If the probability of winning is not influenced by the quantity offered, then the second term on the right hand side of condition (5) is 0. In this case, condition (5) requires that the quantity be selected so that the marginal cost equals the price bid. If, on the other hand, increasing the quantity bid will decrease the probability of the bid's acceptance, then the second term on the right hand side of (5) will be negative and this will result in a lower value of Q being optimal.

If we paramaterize C(Q) and Pr(P,Q), we can get more specific formulas. One simple parameterization makes the following assumptions:

1) The cost function is quadratic:

$$C(Q) = a + bQ + cQ^2 \text{ , } a,b \geq 0, c > 0; \tag{6}$$

2) The probability of an offer being accepted is given by the complementary cumulative Weibull distribution with Q having a linear trade-off against P:

$$Pr(P,Q) = e^{-\alpha(P+\eta Q)^m}, \alpha, m > 0 \text{ , } \eta \geq 0. \tag{7}$$

With these assumptions, the optimal value of P for given Q is the solution of

$$P = \frac{a + bQ + cQ^2}{Q} + \frac{1}{\alpha m(P+\eta Q)^{m-1}} . \tag{8}$$

The optimal value of Q for given P is the solution to

$$Q = \frac{P-b}{2c} - \frac{\left[(P-b)Q - a - cQ^2\right]}{2c} \alpha m \eta (P+\eta Q)^{m-1}. \tag{9}$$

If we specialize the Weibull distribution to the exponential distribution by setting m=1, then we can solve (8) and (9) analytically for the optimal P and Q. With this specialization, the maximum acceptable price at capacity zero has mean $1/\alpha$. Equation (8) becomes:

$$P + \frac{a + bQ + cQ^2}{Q} + \frac{1}{\alpha} = \frac{a}{Q} + b + cQ + \frac{1}{\alpha} . \tag{10}$$

Substituting for P in (9) and simplifying yields

$$Q^2(c+\eta) - \frac{Q}{\alpha} - \alpha = 0 \qquad (11)$$

which, in turn, yields

$$Q = \frac{1 + \sqrt{1 + 4\alpha^3(c + \eta)}}{2\alpha(c + \eta)} \qquad (12)$$

Substituting this into (10) will give an analytic expression for P.

Appendix E

An Example of a Specific Bid Acceptance Algorithm

This appendix gives a specific example of a potential bid acceptance algorithm for a PURPA auction. This algorithm implements a sequential approach, but one in which bids at higher than a marginal bid may be considered after that marginal bid has been rejected as too big and has declined an opportunity to downsize. In calculating the downsizing required for a marginal bid, no downsizing by higher bids is assumed. After the algorithm has been stated, we give an example of its application.

Algorithm

1.) Reject all bids in excess of *Avoided Cost.*

2.) Order all remaining bids from low to high cost per KWh, breaking ties at random. Index these remaining bids in order from $i = 1$ to $i = n$. Start with $i = 0$ and *Quantity Accepted* $= 0$

3.) Increment i *by 1* and then consider bid i

4.) If *Quantity Accepted* + *Quantity Offered by Bid* i < *Utility Power Requirement,*

- Accept bid i
- Increase *Quantity Accepted* by *Quantity Offered by Bid* i
- If $i < n$, go back to Step 3.
- If $i = n$ and bid i has been accepted, end algorithm.

5.) If *Quantity Accepted* + *Quantity Offered by Bid* $i \leq$ *Utility Power Requirement* + *Requirement Tolerance*

- Accept bid i
- Increase *Quantity Accepted* by *Quantity Offered by Bid* i
- End algorithm.

6.) "Value" bid i by setting *Value (i)* = *Avoided Cost* less *Bid i's Price* integrated from *Quantity Accepted* to *Quantity Accepted* + *Quantity Offered by Bid* i.

7.) Calculate *Hurdle* (i) as follows:

(7a) Set *Hurdle (i)* $= 0$

(7b) Set $j = i + 1$

(7c) Set *Quantity Limit* = *Utility Power Requirement* + *Requirement Tolerance - Quantity Accepted*

(7d) If *Quantity Offered by Bid* j < *Quantity Limit*

- increase *Hurdle (i)* by *(Avoided Cost- Bid j's Price)* times *Quantity Offered by Bid j*
- decrease *Quantity Limit* by *Quantity Offered by Bid j*
- if *Quantity Limit* < *Tolerance Limit,* go to Step 7e
- increase j by 1
- if $j > n$, go to Step 7e
- repeat Step 7d

(7e) If *Value (i)* ≥ *Hurdle (i)*

- Accept Bid i
- Increase *Quantity Accepted* by *Quantity Offered by Bid i*
- End Algorithm

8.) Find the required downsizing level for bid i by calculating, *S (i),* the largest value less than the *Quantity Offered by Bid i* such that the integral of *Avoided Cost* less the *Price of Bid i* from *Quantity Accepted* to *Quantity Accepted + S (i)* is *Hurdle (i)* and then setting the *Downsizing Requirement* for bid i at the maximum of *S (i)* and *Utility Power Requirement + Requirement Tolerance - Quantity Accepted.*

9.) Solicit a *Downsized Offer* from bidder i at his prior price and for any quantity between the quantity calculated as his *Downsizing Requirement* and *Utility Power Requirement - Quantity Accepted.* If such and offer is received in a timely way,

- Accept bidder's *Downsized Offer*
- Increase *Quantity Accepted* by bidder *i's Downsized Offer.*
- End Algorithm

10.) In the absence of a timely downsizing offer by bidder i,

- If $i < n$, go back to step 3
- If $i = n$, end algorithm.

For an example, consider the application of this algorithm to the situation given in Table E-1.

TABLE E-1

Utility Power Requirement: 500MW
Requirement Tolerance: 50MW
Avoided Cost:

0 to 550 MW	10¢ per KWh
550 MW to 750 MW	8¢ per KWh
750 MW to 1000 MW	5¢ per KWh

Bids Received

Bid # (i)	Quantity Offered, MW	Price Per KWh
0	100	11.0¢
1	300	8.5¢
2	100	9.0¢
3	300	9.5¢
4	50	9.6¢
5	200	9.7¢
6	80	9.8¢
7	400	9.9¢

In applying the algorithm, bid *0* is rejected at step 1. Bids 1 and 2 are accepted at step 4. Bid 3 then fails steps 4 and 5. With 400 MW of power accepted, the value of the bid is calculated as:

$$\text{Value } (3) = 150\ (.10 - .095) + 150\ (.08 - .095) = -\ 1.5,$$

and the Hurdle for Bid 3 is calculated as

$$\text{Hurdle } (3) = 50(.10 - .096) + 80\ (.10 - .098) = .36.$$

Thus, bid 3 fails the test of step 7. In step 8, $S\ (3)$ is the solution to the equation $150\ (.10 - .095) + [S(3) - 150]\ (.08 - .095) = .3H$. This solution is $S(3) = 176$. If bidder 3 will supply between 100 MW and 176 MW at 9.5¢ per KWh, his downsized bid is accepted at step 9 and the algorithm ends rejecting all other bids. If not, his bid is rejected. Then, bid 4 is accepted at step 4, and the maker of bid 5 is offered at Step 9 the opportunity to downsize to a capacity between 50 MW and 108 4/17 MW. If this offer is accepted, the algorithm ends rejecting bids 6 and 7. If not, bid 6 is accepted at step 5. Finally, bid 7 is rejected because the algorithm has ended without its acceptance.

Appendix F
Extending the Auction Mechanism to all New Electricity Generation*

1. Introduction

This appendix considers the factors involved in extending an auction framework for PURPA power purchases to all new generation. To fix the dimensions of the discussion, we will first characterize the auction process as it would apply to PURPA purchases. This characterization is designed to highlight the qualitative roles of utility, regulator, and bidder in the process. With these roles defined in the PURPA case, we can then examine what changes would be necessary when we extend the range of technologies and remove limitations on the class of bidders. The discussion will be organized around three main themes.

First, we address issues associated with a redefinition of the utility's main business function. Generalizing the auction mechanism has the effect of breaking the vertical integration of the generation with the transmission and distribution functions of the utility. We must define the obligations and limitations of the utility as a regulated supplier. Will it always remain the supplier of last resort? Is it allowed to bid as an unregulated entity to supply generation to its own ultimate customers? If tbe utility competes in the generation market outside the territory of its own ultimate customers, how are these business risks separated from the regulated field of operation? We will suggest that the self-dealing problems associated with bidding to supply its own generation requirements are considerable, so the utility should not be allowed to take such action.

The second set of issues we address involve resource planning. The auction process does not eliminate the need for long-term planning of electric power supply. Government regulation will continue to play a role in this planning process. The first stage of an auction process is a determination of need. The issues involved here on the demand side include the assessment of demand-side resources and the responsibility of the utility to supply resale customers. There are also supply-side issues involving the role of the utility as supplier of last resort. These issues include the question of deciding when to retire existing units, whether they should be refurbished, and, if they are sold off, under what conditions that will occur. Finally, the role of the transmission system becomes central. Bids must be evaluated with respect to their impacts on the transmission network.

*Helpful discussions were provided by Mark Levine of LBL and Susan Morse of MRW and Associates.

Bidders may propose transmission as part of their bids. How these factors are evaluated becomes important.

The last set of issues is pricing related. Although bidding is expected to introduce economic efficiencies, it will also create new kinds of pricing problems. Some of these are related to the contractual relations between suppliers and purchasing utilities. Suppliers will have an economic incentive to shift various economic risks to the purchaser through contract terms. Evaluating these risks is complicated. Furthermore, there may be overlapping regulatory jurisdictions in the case of resale customers. The latter are regulated by FERC, whereas the retail sales of the utility are regulated by the state commissions.

2. The Auction Process for PURPA Purchases

Although many unsettled questions surround the details of appropriate auction procedures for PURPA purchases, a broad outline can be delineated. It will be useful to sketch the process as a background to the discussion of its potential extension. We distinguish five stages to the auction process. These stages are the determination of a long-run power requirement, the estimation of avoided cost, the solicitation and evaluation of bids, the bid acceptance procedure, and, finally, the repetition of the entire process at specified intervals.

2.1. Need Determination

The amount of power to be purchased must be determined. This is both a load forecasting exercise and a supply planning process. Among the issues involved in load forecasting are the various measurements of conservation activities, including both price-induced and programmatic effects. The supply issues include accounting for reductions in available resources as a result of contract expirations or unit retirements. Reserve margin requirements are also involved. Together these activities constitute need determination. The California Energy Commission has been engaged in a process of this kind for nearly ten years (CEC, 1986). It applies the results of this process in its facility siting cases to all power projects above 50 MW whether they are utility sponsored or PURPA projects. Other states are adopting a similar process.

2.2. Avoided Cost Estimation

Estimating avoided cost is the step after need determination. There is no such thing as an avoided cost in general, but only one that is tied to particular quantities. The utility has a demand curve for purchased power, which can be estimated by simulation models. It is common to make a single estimate of avoided cost that is tied to the quantity deemed needed. For reasons discussed below, it will often be convenient to estimate the avoided cost for quantities in excess of the need increment. Since need is not an all or nothing process, there must be some value for power beyond the need increment identified in the first stage. This value is necessarily less than avoided cost for the need increment, because of diminishing returns. Under PURPA, state regulatory agencies must approve the avoided cost estimate.

One unique feature of the auction process is the long-term nature of the avoided cost concept. Under PURPA, avoided cost prices may be either short term in nature or long term or both, depending on the choice of the state regulatory authority. Bidders who will make capital investments to supply power, however, need longer term price assurance to secure financing. The term of these offers need not be equal to the full economic life of the projects. It must, however, cover the ten-to-fifteen-year period during which such projects must pay off their bank debt.

2.3. Bid Solicitation and Evaluation

Once need has been determined and avoided cost estimated as the upper bound on bids, bids will be solicited. There is some need to assure that bids are serious. At the least, non-serious bids will distort auction results. At worst, they can form part of collusion or bid-rigging strategies. Seriousness can be demonstrated by detailed specification of project characteristics which may also be necessary for evaluation purposes. Alternatively, bidders can be required to make deposits or to post bonds.

Once bids have been made it is common to reduce them to a single metric. This is important in power auctions because there are a number of features to project bids that will not necessarily all be comparable. Among the most difficult features to evaluate are bids including special pricing terms. The avoided cost ceiling, because of its long term nature, may be expressed as an escalating stream of payments. Bidders may seek a levelized payment stream to meet financing requirements on capital intensive technology. Because levelization implies an exposure of the purchaser to the risk of premature project abandonment, there is a cost to this feature. It is difficult to put a value on this risk exposure. Bid evaluation schemes proposed in Massachusetts provide complex formulas that in effect tradeoff price against risk and other factors (Boston Edison, 1986 and Western Massachusetts Electric, 1986).

It is not strictly necessary to reduce bids to a common metric. All that is really necessary is to come up with a rule for accepting a set of winners that produces a fair, efficient outcome with good motivational features. It is a matter of some procedural subtlety whether this rule be embodied in the evaluation stage or in the acceptance stage.

2.4. Bid Acceptance Procedure

There are a variety of methods to choose the set of winning bids. We will ignore the details to focus on the one issue which can cause the most difficulty, the lumpiness of project size. Power projects do not come in a continuously available capacity range. Equipment size exists in discrete chunks. It is possible that when a fixed need has been determined that the lowest cost set of bids on a per unit basis will yield more capacity than is desired. Among the procedures suggested to ameliorate this problem are allowing a 10% tolerance on the size of the capacity need block and recalculating the avoided cost for quantities larger than the need block (Massachusetts, 1986). Other alternatives include allowing the marginal bidder to downsize his project to meet the capacity block limit (SCE, 1986) and allowing bidders to make multiple bids in the expectation that the aggregate lumpiness of all bids will be reduced.

2.5. Iteration of the Auction Process

Auctions will not necessarily result in a perfect match between needs and ultimate supplies. There may be project failures or inaccurate forecasts of needs. Even without such events the sum total of power produced by successful bidders may not have all the desired characteristics. The natural increase in load requirements over time combined with all these contingencies will result in the need for future auctions. To some degree the choices made at each stage of earlier auctions will influence future requirements, and therefore the frequency of auctions. The "optimal" auction frequency results from balancing the risks of too frequent intervals against too infrequent. The risks of excessive frequency include the development of collusion among bidders. If auctions are too infrequent, suppliers may be discouraged from staying in the industry. Infrequent auctions also induce planning inflexibility. It may be anticipated that auctions will occur on a two-to-three-year cycle. This will give successful bidders a chance to complete the development process. Changing economic conditions can also be factored into the need determination process to correct mistaken estimates from the last iteration.

3. Breaking Up Vertical Integration: Re-defining the Utility's Role

Generalizing the auction process beyond the PURPA framework implies a significant redefinition of the utility's role. In this section we will describe the reasons for this change, sketch the new opportunities available, and characterize the kinds of obligations and limitations likely to remain with the utility.

3.1. The Removal of PURPA Limitations

Generalizing the auction mechanism beyond the PURPA framework means removing restrictions on which technologies can be used for supplying power under bidding, and who may own them. PURPA placed size and fuel type limitations on projects that sought Qualifying Facility (QF) status as unregulated suppliers. Renewable energy projects (wind, solar, biomass, geothermal and hydro) had to be less than 80-MW. Cogeneration projects could be any size but had to meet a minimum efficiency test associated with the non-power use of thermal energy. Fossil-fired generation which did not meet such tests could not be considered a QF. Thus, standard utility-scale coal-fired generation without any cogeneration could not qualify under PURPA.

Utilities were also forbidden under PURPA from being more than 50% owners of any Qualifying Facility. During the last few years, more and more utilities have formed subsidiaries to pursue QF opportunities both in their own service territories and in territories of others. This experience suggests that with removal of PURPA limitations at least some segment of the utility industry would expand its activities in the unregulated supply market.

One model for the entry of utilities into the unregulated power market is the export joint venture project. There are currently at least two large-scale joint ventures involving utilities, engineering firms, equipment vendors and financial institutions planning coal-fired generation for the resale market. These projects are the New Mexico Generating Station (NMGS) being planned on Navajo land in New Mexico and Wells Energy Park in Central Nevada. Both of these projects are designed in one way or another to avoid the current system of state regulation for construction permits and pricing. Elimination of the PURPA restrictions would make such projects easier to assemble. It is likely that ventures such as NMGS and Wells would be the outcome of removing the PURPA limitations.

It is an open question whether the removal of PURPA limitations will, in fact, induce large-scale power projects. Financing is one important constraint to multi-billion dollar endeavors. The largest privately financed projects to date represent much smaller commitments. One example is the Ocean State Power project being planned in Rhode Island. This 235-MW combined cycle plant has an estimated construction cost of about $150 million. It will be FERC regulated under a proposed tariff that includes rate of return incentives for high availability. The financial commitment to Ocean State is about the same as that to large PURPA cogeneration projects planned in Texas and California.

For auction systems to provide a means of building coal or nuclear projects, it will be necessary to raise on the order of a billion dollars. A 500-MW plant costing \$2,000/kW will require one billion dollars. Smaller units and/or lower costs might reduce this somewhat, but the amounts involved are larger than those commonly committed in single-auction transactions involving risky assets.

3.2. The Self Dealing Problem

One problem that emerges when the ownership restriction of PURPA is dropped is the potential for distortions resulting from self-dealing. When the utility is both bidder and bid-taker in an auction there may be reason to think that transactions are not arms-length in nature. Current arrangements show this concern on the part of state regulators. The Michigan Public Service Commission is holding hearings on a proposed avoided cost methodology that would use a particular utility plant as the basis for avoided cost and make payments to that same plant based on the determined rate. There is a problem being on both sides of the bargaining table (*Energy Daily*, 1986).

To remedy such concerns the Wells Energy Park project is proceeding under a Nevada law that exempts it from state regulation on the condition that the power be sold for export out of state. When the utility does buy from its own affiliate, special protection is required. Niagara Mohawk's unregulated subsidiary Hydra-Co sells QF power to the parent company under a strict power contract which provides for repayment of revenues above avoided cost with interest. Although individual situations can be handled on a case by case basis, it is not clear that accommodation is so easy when self-dealing becomes a generic possibility.

The simplest means of eliminating the self-dealing problem is to exclude the utility from bidding to meet the requirements of its own customers. Utilities would still be allowed to compete in the service territories of others. Such activity would be just an extension of current practice under PURPA restrictions. Alternatively it can be thought of as analogous to the export-only requirement of the Wells Energy Park project. This limitation can deflect the suspicion that the bidding process has been rigged.

A more sophisticated version of the self-dealing problem is potential collusion with other utilities in the form of market-sharing agreements. Utility A bids in the territory of Utility B and vice versa. The two companies agree privately to accept each other's bids in a manner that shuts out competition from non-utility bidders. This kind of bid-rigging has been documented in the construction industry. To prevent occurrences of this kind, it is important to have rules for bid acceptance that are sufficiently public so that competitive forces will serve as an effective policing agent.

3.3. The Supplier of Last Resort Obligation

Currently PURPA assumes that the utility will remain the supplier of last resort. QFs were not thought to form a major element in the supply mix in the initial implementation of PURPA. The whole notion of avoided cost is based on the presupposition that the utility supplies the most of the power whose costs determine the value of QFs. Under a long-run auction framework it will no longer be true that the utility is the dominant supplier. It may cease to be a supplier at all on an incremental project basis. If all new power requirements are met by auction, the notion of avoided cost begins to lose its traditional meaning as the cost of alternative utility supply.

Under a generalized auction regime, it remains a question whether the utility will retain a role as the supplier of last resort. If this role is retained, then the utility will make incremental investment in generation capacity of some kind. It may be desirable to retain such a role for purposes of system integration. Because electric power has significant real-time operational constraints, centralized control is necessary to maintain system integrity. The integrated utility has traditionally played this control function both for short-term operational planning and for long-term planning. Since the function will still be required, it may be desirable to keep a regulated entity performing it.

The kind of capacity required by the supplier of last resort is probably more of the intermediate and peaking nature than of the baseload nature. This conclusion follows from the assumption that it is the integration and control function that dominates the "last resort" situation. If this were not the case, then "last resort" would be more akin to a base-load bidder shortage situation. This means the utility would actually have to build new baseload facilities under regulated conditions. Such a situation is inconsistent with a sustainable competitive supplier market. In this case, it is difficult to imagine successful deregulation. The success of PURPA to date in inducing a large-scale supply response suggests that competition in bulk power supply is possible in the long run. With the entry of new technologies, purchasing bulk power looks even more sustainable. The occasional need for backstop construction by the utility need not signal a return to pre-auction conditions.

In section 4, we will describe the evolution of the planning function under a generalized auction market for bulk power. The utility will still retain responsibility for the planning and integration of new supplies to meet demand. To some degree this may even involve continued investment in generation technology. Before describing the changes in the planning function in more detail, we must characterize the problem of separation between the utility's regulated and unregulated activities.

3.4. Separation of Regulated from Unregulated Activities

The principal mechanism currently used by utilities to separate their regulated and unregulated activities is the holding company. The holding company is a financial shell whose assets are separate subsidiary companies. The regulated utility is one of these companies; other subsidiary companies engage in unregulated activities. Each of the operating companies has its own debt capacity (selling bonds or borrowing from banks), but only the holding company sells common equity stock. Earnings from the subsidiaries are paid to the holding company and form the basis of dividends paid to owners of the holding company stock.

Utilities operated in the holding company framework to a substantial degree during the formative period of the industry's development. Certain abuses of this form occurred that led to regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act (PUCHA) of 1935. One of the principal aims of SEC regulation is to assure than the regulated operations are not unfairly burdened by unregulated activities. This concern includes prevention of excessive payments for services and the inappropriate use of financial power.

These concerns can be expected to persist as the utility industry moves to a competitive auction market for bulk power. Whether SEC regulation or state commission oversight is the best means of monitoring activities remains to be seen. But the problem of insulating the ratepayers of the regulated activity from the business risks of unregulated action will still be a social concern. PUCHA must not be allowed to restrain private power suppliers unnecessarily. Just as PURPA provided exemption from utility status for Qualifying Facilities, it may be desirable to alter PUCHA so bidders would not be subject to additional regulation.

4. Resource Planning

Resource planning may well become more complex analytically in a competitive auction market for bulk power, than in the vertically integrated industry model. The additional complexity is the costs associated with the efficiency benefits of competition. In this section, we discuss briefly four issues that will become more difficult to handle in the competitive auction market. The first problem is load forecasting and the associated question of demand-side planning. The utility must determine the need for new sources of bulk power (see section 2.1). This involves the tradeoff of supply with demand-side options on the one hand, and meeting the needs of resale customers on the other. Secondly, transmission system use becomes more complex under bulk power auction mechanisms. Bids involve impacts on the power grid that are difficult and costly to model and ameliorate. Thirdly, the role of supplier of last resort involves the optimization of retirements of existing facilities or their continued service through life-extension and refurbishment. Finally, the bid acceptance process will probably be more constrained by lumpiness problems as larger scale projects bid to supply power.

4.1. Load Forecasting and Demand Side Resources

The determination of need for new bulk power resources has traditionally relied on passive load forecasting methods. These methods are passive to the degree that they do not involve large-scale active intervention by the utility to structure the demand by end users. Recently utilities have become more active on the demand side, marketing various conservation, load-shifting or off-peak load building programs. These actions are usually subject to economic evaluation against some measure of the utility's marginal cost. Demand-side programs will become more difficult to evaluate under an auction system of bulk power acquisition. The reason for this is the cost of new increments of power will be determined by the auction process, and cannot be assumed to be known before that. To the extent that the cost of power purchased under bidding determines the utility marginal cost, bidding will reduce the ability to estimate marginal cost.

These same considerations apply to the resale loads supplied by utilities. For communities whose distribution utilities are "full-requirement" customers of other utilities, the forecasting uncertainties are identical. In this case, however, the supplier-utility does not even have the discretion over demand-side programs. This discretion will reside with the purchaser-utility. In the case of "partial-requirement" customers, there is not much concern about demands since these utilities must contract with their suppliers. In both cases, price uncertainties can be expected because of the unknown auction prices ex post. These price uncertainties may be no worse than current difficulties in forecasting the price of power.

Individual utilities will develop their own approaches to demand-side resources. In some cases this may lead to identifying demand-side programs as backstop avoided cost. Such an approach would probably have to include incentive payments to customers and might even extend to the outright purchase of equipment. An alternative treatment would be to allow bidders to offer demand-side resources in the auction directly. This has been proposed by Lovins. It is not likely that this treatment of demand-side resources will be widely adopted. The principal problems are measurement and moral hazards.

Measurement problems are among the major difficulties in evaluating demand-side programs for resource planning. Even utilities offering demand-side resources as a backstop avoided cost face measurement problems. Bidders, however, would have an economic incentive to overstate the magnitude of their offered savings. The critical question involves consumption levels that might have occurred without demand-side intervention. These are difficult to verify. Although private parties have negotiated "shared savings" contracts that deal with such issues in individual cases, these arrangements are difficult to generalize. Bidding such programs in a power auction amounts to envisioning a general structure in which all particular variations can be accounted for. In individual cases, it may be possible for utilities to verify third-party arrangements, but in general this is harder to imagine without punitive steps such as demand limiters or performance bonds.

4.2. Transmission

Bidders must deliver their power to the utility transmission system. Even under PURPA in its present form, there can be limitations on the ability of the grid to accept output in given locales. In Northern California, QFs have been constrained by insufficient transmission capacity. A queueing system has evolved to ration the available capacity, but such solutions are not long term. It is more likely that the bidders will have to follow the model of other California QFs who have decided to fund their own transmission line to "extend the interconnection facility" as one of the sponsors says (W. Meek, 1986). Another example is in central Nevada where geothermal developers are constructing a 200-mile transmission line that will connect with the Southern California Edison system (Oxbow Geothermal, EIS).

If we assume that projects will have to bear some incremental transmission costs, then the bid preparation process must include an estimate of these costs. There is a non-linearity to this problem because the transmission capacity at a given point in the network depends on the entire network configuration. Even developing initial estimates of transmission capacity requires expensive analysis.

Given the central role of transmission capacity, an important policy question surrounds the philosophy under which it will be operated. Electric transmission can evolve along the common carrier model. In this framework, equal access at competitive prices is the guiding principle. The potential for monopoly power and profits is suppressed in the interest of lower consumer costs. This model has been influential in the evolution of natural gas pipeline transmission policy at FERC.

The greater technical complexity of electric power transmission will make it more difficult to reduce monopoly power than in the natural gas case. Operators of the power network are better able to disguise cost and prevent regulation from reducing price. In the extreme, utilities would auction off transmission capacity to the highest bidder, thereby exacting a scarcity rent. A proposal of this kind was recently made to FERC by Baltimore Gas and Electric (Electrical World, 1986). It was not accepted.

Although the common carrier model for electric transmission has not been accepted, there are indications that regulators find it attractive. The most noteworthy instance of this is the mandatory wheeling requirement imposed by the Texas Public Utility Commission for cogenerated power. Given the large supply of cogeneration available in the Houston area, the Texas PUC has ordered that power from these projects be wheeled to other utilities in the state (Texas Administrative Code, 1985). At least one large-scale project has taken advantage of this situation by selling to Texas Utilities in the Dallas area. A similar proposal for mandatory wheeling has been made in New Jersey (New Jersey Department of Energy, 1985).

The eventual role of transmission in planning for power auctions will depend to a large degree on the outcome of the policy issue. If the common carrier model is adopted, then bidders' costs will be lower and the amount of cooperation they receive from purchasers will be greater. If the monopoly control of transmission remains in the hands of purchasing utilities this will increase their profits and their power over bidders.

4.3. Retirements and Refurbishments

Utilities will still have capacity planning and investment decisions under a bulk power auction system. At a minimum, the decision to retire existing capacity must be made. If, as suggested above, the utility remains a supplier of peaking and even intermediate power, then it will need to assess the value of refurbishing old units or even building new capacity of this type. The economic evaluation of these choices will be complicated by the same factors that affect the evaluation of demand-side resources. Bidding tends to increase uncertainty about future marginal costs, but this is a second order effect.

Even in the scenario in which the utility eventually exits completely from generation activities, there will be concern about the process of retiring existing capacity and disposing of it. The rate of retirement is not necessarily obvious. It is straightforward to compare the total cost of existing facilities with the cost paid to bidders at the last auction. But the relevant comparison is with the unknown cost of future bids to replace a retired facility. It will be useful for all the planning activities to develop models that can forecast the results of auctions.

Retired facilities must be disposed of on an arms-length basis. The sites for power plants are themselves valuable assets. They are close to fuel delivery systems. Cooling water is usually available. And the surrounding area is accustomed to power production activity, so environmental mitigation is reduced. Furthermore, the equipment on these sites will have value to purchasers. If the utility chooses not to refurbish these sites, it may be economic for a bidder to do so. For all these reasons, it is important that the utility receive adequate compensation when it disposes of retired facilities.

4.4. Lumpiness

In section 2.4, we referred to the lumpiness problem in bid acceptance. Because the utility will purchase a fixed amount of power and bidders will offer blocks of varying magnitudes, it may not be possible to accept the lowest average cost producers. A simple and somewhat extreme example will illustrate the problem. Suppose that the utility wants to purchase 200 MW. One bidder offers MW150 at $4/MWh, another offers 50 MW at $5/MWH and a third offers 100 MW at $4.50/MWh. The last bidder would have to be rejected because of the quantity limit, even though his average cost was less than the 50MW bidder. Thus, lumpiness prevents us from accepting the lowest average cost bidders. As we indicated above, there are several ways to mitigate this problem. The tradeoffs have been described elsewhere. What is important for present purposes is that lumpiness may prove more constraining under a generalized auction market for bulk power than in the PURPA case.

The reason that lumpiness may be more constraining is the expectation that larger projects will bid when PURPA limitations are removed. Removing the PURPA restrictions on technology will allow coal-fired generation projects that do not have cogeneration applications and gas-fired combined cycle plants. The scale of these technologies is on the order of 250-500 MW in the first case and 200 MW in the second. Although there have been PURPA cogeneration projects of approximately this size, these are extremes and not typical. In general, lumpiness is more constraining as the ratio of project size to need increment increases.

One mitigation strategy that has not been analyzed previously is to lengthen the planning horizon. This will have the effect of increasing the need increment and thereby reducing the binding nature of lumpiness problems. Such procedures will increase the demand forecasting risk and reduce the frequency of auctions. Neither of these are desirable effects. Forecasting errors grow with the length of the planning horizon. Infrequent auctions may make it difficult for an industry to develop.

A desirable alternative would be technological change that lowers the minimum efficient scale for these types of projects. Fluidized bed combustion of coal will become available in smaller unit sizes than conventional coal-fired generation for example. Advanced gas turbines, which are the heart of combined cycle systems, may also have smaller capacity, because they have military applications for which substantial R&D funding is being invested in smaller scale operations.

5. Pricing

In this section, we will consider two kinds of pricing issues. First, we explore contract terms which expose the purchaser to default risk. These are cases in which the seller is paid more than avoided cost in some years and less in others. The second issue we discuss is the overlap in jurisdictions involving FERC Full Requirements customers of utilities.

5.1. Default Risk

Bidders selling power to utilities will have an economic incentive to shift risks to the purchaser through contract terms. QFs, under the current PURPA framework, have sought pricing concessions that reduce their risk. The most common form of this risk shifting is to contract at prices which exceed avoided cost values at the beginning of the project life. This is necessary for developers because avoided costs typically escalate over time from a low initial level. Projects must amortize fixed costs whose burden is greater in the initial years of operation. The mismatch in the timing of project costs and avoided cost values creates the need for contract terms that close the gap. The purchaser will agree to pay in excess of avoided cost in the early years of a project in exchange for paying less in future years. Accepting such an arrangement exposes the purchaser to some default risk.

Utilities may already have exposure to default risk through QF contracts under PURPA. Auction systems for PURPA purchases can, in principle, reduce this exposure in the future by evaluating less favorably bids that imply such exposure. The bid evaluation scheme used in Maine does this, and those proposed in Massachusetts also have the same effect. To the extent that the avoided cost trajectory and bidder's payment requirement conflict, however, it may be necessary to incur some exposure to default. In that event, it is questionable whether generalizing the auction process to all technologies will magnify or reduce the problem.

Default exposure will increase in the aggregate because of the lumpiness effect of having larger projects bid. The magnitude of the exposure is a function of project size. As discussed above, removing the PURPA limitation on technologies will imply that project scale increases. For capital intensive technologies such as conventional coal-fired generation, the gap between avoided cost and payment requirement may increase the amount for "front-loading" necessary for financial feasibility. Technical progress may work in the opposite direction, reducing project size and perhaps also capital intensity.

Aggregate default exposure is also a function of the correlation of risks among the portfolio of projects whose output is sold to utilities under front-loaded contracts. Removing PURPA restrictions should be beneficial in diversifying risk. The reasons one project defaults are not necessarily the same as those for another. Therefore, technological diversity reduces risk.

A final relevant factor is the financial capability of the bidder. If a major industrial corporation is bidding to supply power, the likelihood of default is much less than with an undercapitalized entrepreneur. Removing PURPA ownership restrictions will have the beneficial effect of adding more financial capability to the mix of bidders, which will offset to some degree the detrimental impacts on default risk of a generalized bulk power auction market.

5.2. Jurisdictional Conflict

Utility rates to systems that purchase power from other utilities are regulated by FERC. The procedures adopted by FERC are based on cost of service. This means that the rate of return earned by suppliers subject to FERC regulation is strictly limited. Auction systems, on the other hand, are market oriented. The profits of producers are not directly relevant to the determination of prices. It is assumed that competition limits the potential for unusual profit. When utilities purchase power in an auction procedure and resell it under situations regulated by FERC, there is a potential conflict of pricing principles.

This potential for conflict rests on the supposition that FERC will not change its regulatory practices to accommodate changes in the competitive structure of the electricity market. Recent evidence on this issue is mixed. On the one hand, FERC did recently reject an auction proposal for unused transmission capacity on the grounds that the benefits of an auction were not demonstrated. On the other hand, FERC has initiated experiments in wholesale power exchange that are based on market principles. More importantly it has modified its regulation of private production for wholesale power by authorizing a productivity oriented pricing arrangement for the Ocean States Project in Rhode Island. Although still formulated as a cost-of-service tariff, the contract does allow for higher returns on the project when performance meets certain specified levels (FERC, 1986). This incentive for technological improvement is a positive step in the direction of market oriented pricing. The extent to which it signals a change in regulatory philosophy remains to be seen.

6. Conclusions and Research Agenda

In principle, it is possible to extend the auction framework beyond PURPA to include all new electricity generation. This does not mean that such a transition will be without uncertainties and difficult policy choices. The main questions that this incremental form of deregulation pose involve the definition of future rights and responsibilities of the regulated entity that will remain. Will the utility be able to extract scarcity rent from the control of the transmission system? Will its function as supplier of last resort involve major capital investments, and, if so, of what kind? What rules will govern the liquidation of existing facilities?

Answers to these questions depend to a large degree on the particular institutional and resource environment in which they are posed. Utilities in a regional power pool need not provide the kinds of integration services that a stand-alone utility must provide. Similarly, the regional resource endowment will determine the kinds of incremental investment opportunities that exist and the resources that the utility will have under its control.

In many ways, the ability of the utilities to integrate a bulk power auction market reduces to constructing the kinds of contractual relations with suppliers that can cover the contingencies that arise in operating power systems. This point has been made by Joskow and Schmalensee (1983). To design a research program addressing the feasibility of a completely open bulk power auction market, we suggest the following approach. We distinguish two kinds of power need situations, baseload and marginal. The baseload situation essentially resembles the PURPA market. There is an obligation to purchase which means that output is dispatched in the base load. Marginal power, on the other hand, is dispatchable by definition. In this case, the producer must be controlled to meet system needs. Thus, his expected production will have substantially greater variance than the baseload producer. We propose exploring the feasibility of writing contracts that cover contingencies in each of these two cases.

The research agenda should explore contract feasibility under contingencies for baseload and marginal power in a variety of institutional and resource settings. Studying a range of settings because it will define the relevant range of contingencies and response mechanisms. A region with substantial hydro resources, for example, has fluctuations in the need for marginal power that are induced by hydrologic variation. This is distinctly different from thermally based systems. Similarly, power pools have coping mechanisms that stand-alone utilities lack. The analysis of contracts should include both issues related to auction form and the implications of contracts for bidders' investment risk.

A method to examine these issues would combine traditional utility costing tools with private investment analysis and the simulation of auction markets. The utility costing tools (such as production cost simulations) would estimate the value of maintenance scheduling, unit commitment and dispatchability. These values would be expressed with variances to account for uncertainty and variability of conditions. The private investment analysis would be used to estimate the cost of insuring against the contingencies identified in the utility cost analysis. This insurance would take the form of a risk premium required for the contingencies. Finally, the auction simulations would be used to estimate whether competition would lower costs compared to the regulated case.

A method such as this could be expected to differentiate between the conditions favoring auction markets for baseload versus marginal power. Definitive estimates would not be practical because of limited information about private costs and the extent of competition. The exercise of this method would help sharpen perceptions of the tradeoffs and develop tools necessary to implement the institutions of a more decentralized power system.

Appendix G

Cost Curves

Representative Bidder A

QF Cost Function 1996 — No Scale Economies Above 150MW

Gas Turbines								
Capacity (MW)	175	150	125	100	75	50	25	5
Capital Cost ($M)	186	159	138	115	91	66	38	10
$/KW	1062	1062	1101	1151	1218	1320	1514	2082
Annual Charge Rate	0.17	0.16	0.15	0.15	0.15	0.15	0.15	0.15
Annual Charge ($M)	32	25	21	17	14	10	6	2
Hours	6750	6750	6750	6750	6750	6750	6750	6750
Heat Rate (Btu/kWh)	10500	10500	10500	10500	10500	10500	10500	12000
Fuel Cost ($/MMBtu)	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Annual Fuel Bill ($M)	98	84	70	56	42	28	14	3
Steam Load (MMBtu/hr)	150	150	150	150	150	130	80	20
Net Electric Heat Rate	9643	9500	9300	9000	8500	7900	7300	8000
Value of Steam	10	10	10	10	10	9	5	1
On-Site Electricity Credit								
Load (MW)	10	10	10	10	10	10	10	10
Value @ $12/MWh	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81
Unit Cost	0.1005	0.0974	0.0946	0.0925	0.0887	0.0842	0.0802	0.0776
Marginal Cost	0.1191	0.1117	0.1030	0.1040	0.0976	0.0882	0.0809	

Representative Bidder B — No Scale Economies Above 150MW

Gas Turbines								
Capacity (MW)	175	150	125	100	75	50	25	5
Capital Cost ($M)	186	159	138	115	91	66	38	10
$/KW	1062	1062	1101	1151	1218	1320	1514	2082
Annual Charge Rate	0.17	0.16	0.15	0.15	0.15	0.15	0.15	0.15
Annual Charge ($M)	32	25	21	17	14	10	6	2
Hours	6750	6750	6750	6750	6750	6750	6750	6750
Heat Rate (Btu/kWh)	10500	10500	10500	10500	10500	10500	10500	12000
Fuel Cost ($/MMBtu)	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Annual Fuel Bill ($M)	98	84	70	56	42	28	14	3
Steam Load (MMBtu/hr)	60	60	60	60	60	50	30	10
Net Electric Heat Rate	10157	10100	10020	9900	9700	9500	9300	10000
Value of Steam	4	4	4	4	4	3	2	1
On-Site Electricity Credit								
Load (MW)	5	5	5	5	5	5	5	5
Value @ $12/MWh	0.405	0.405	0.405	0.405	0.405	0.405	0.405	0.405
Unit Cost	0.1060	0.1038	0.1022	0.1020	0.1013	0.1012	0.1023	0.1093
Marginal Cost	0.1191	0.1117	0.1030	0.1040	0.1015	0.1001	0.1006	

Representative Bidder C — No Scale Economies Above 150MW

Gas Turbines									
Capacity (MW)	250	175	150	125	100	75	50	25	5
Capital Cost ($M)	266	186	159	138	115	91	66	38	10
$/KW	1062	1062	1062	1101	1151	1218	1320	1514	2082
Annual Charge Rate	0.19	0.17	0.16	0.15	0.15	0.15	0.15	0.15	0.15
Annual Charge ($M)	50	32	25	21	17	14	10	6	2
Hours	6750	6750	6750	6750	6750	6750	6750	6750	6750
Heat Rate (Btu/kWh)	10500	10500	10500	10500	10500	10500	10500	10500	12000
Fuel Cost ($/MMBtu)	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Annual Fuel Bill ($M)	140	98	84	70	56	42	28	14	3
Steam Load (MMBtu/hr)	250	250	250	250	240	180	120	60	20
Net Electric Heat Rate	9500	9071	8833	8500	8100	8100	8100	8100	8000
Value of Steam	17	17	17	17	16	12	8	4	1
On-Site Electricity Credit									
Load (MW)	10	10	10	10	10	10	10	10	10
Value @ $12/MWh	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81
Unit Cost	0.1025	0.0949	0.0909	0.0867	0.0836	0.0847	0.0862	0.0881	0.0776
Marginal Cost	0.1202	0.1191	0.1117	0.0990	0.0803	0.0818	0.0843	0.0907	

Representative Bidder D — No Scale Economies Above 150MW

Gas Turbines								
Capacity (MW)	175	150	125	100	75	50	25	5
Capital Cost ($M)	186	159	138	115	91	66	38	10
$/KW	1062	1062	1101	1151	1218	1320	1514	2082
Annual Charge Rate	0.17	0.16	0.15	0.15	0.15	0.15	0.15	0.15
Annual Charge ($M)	32	25	21	17	14	10	6	2
Hours	7500	7500	7500	7500	7500	7500	7500	7500
Heat Rate (Btu/kWh)	10500	10500	10500	10500	10500	10500	10500	12000
Fuel Cost ($/MMBtu)	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Annual Fuel Bill ($M)	109	93	78	62	47	31	16	4
Steam Load (MMBtu/hr)	60	60	60	60	60	50	30	10
Net Electric Heat Rate	10157	10100	10020	9900	9700	9500	9300	10000
Value of Steam	4	4	4	4	4	4	2	1
On-Site Electricity Credit								
Load (MW)	5	5	5	5	5	5	5	5
Value @ $12/MWh	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Unit Cost	0.1033	0.1013	0.0997	0.0994	0.0986	0.0983	0.0990	0.1047
Marginal Cost	0.1155	0.1088	0.1010	0.1019	0.0993	0.0976	0.0976	

Representative Bidder E — No Scale Economies Above 150MW

Gas Turbines												
Capacity (MW)	400	375	350	325	300	275	250	225	200	175	150	125
Capital Cost ($M)	420	399	377	356	334	311	288	264	241	218	195	178
$/KW	1062	1062	1077	1095	1113	1131	1152	1173	1205	1246	1300	1424
Annual Charge Rate	0.18	0.17	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Annual Charge ($M)	76	68	60	53	50	47	43	40	36	33	29	27
Hours	6750	6750	6750	6750	6750	6750	6750	6750	6750	6750	6750	6750
Heat Rate (Btu/kWh)	10500	10500	10500	10500	10500	10500	10500	10500	10500	10500	10500	10500
Fuel Cost ($/MMBtu)	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Annual Fuel Bill ($M)	224	210	196	182	168	154	140	126	112	98	84	70
Steam Load (MMBtu/hr)	750	750	750	750	750	700	650	590	525	450	350	275
Net Electric Heat Rate	8625	8500	8357	8192	8000	7955	7900	7878	7875	7929	8167	8300
Value of Steam	50	50	50	50	50	47	43	39	35	30	23	18
On-Site Electricity Credit												
Load (MW)	20	20	20	20	20	20	20	20	20	20	20	20
Value @ $12/MWh	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62
Unit Cost	0.0918	0.0894	0.0866	0.0838	0.0822	0.0821	0.0819	0.0821	0.0826	0.0839	0.0872	0.0909
Marginal Cost	0.1290	0.1275	0.1240	0.1025	0.0836	0.0836	0.0806	0.0777	0.0738	0.0639	0.0684	

Appendix H

Southern California Edison Avoided Cost

SUMMARY OF UPLAN RUNS FOR IDR CALCULATION

sources:
- purp07 - bare bones for 1996
- purp08 - 1996 with 500 MW coal plant (=IDR)
- purp10 - purp07 with 100 MW perfectly reliable capacity for mc calcs (OIL2)
- purp11 - purp08 with 100 MW perfectly reliable capacity for mc calcs (OIL2)
- purp12 - purp08 with additional 200 MW coal plant for value beyond IDR

DIRECT FUEL SAVINGS

difference in total cost between bare bones supply plan and one with 500 MW coal

run#	total cost
purp07	2929.80
purp08	2818.68
	111.12 million$

INDIRECT FUEL SAVINGS (= CHANGE IN MARGINAL COST TIMES QF VARIABLE PRICE ENERGY)

add 100 MW of perfectly reliable, no cost, must run capacity to each case
divide differences in total costs by output of plant at 100 % cf

value = 68% of qf energy times delta marginal cost

run#	total cost	run#	total cost
purp07	2929.80	purp08	2818.68
purp10	2875.10	purp11	2768.13
	54.70 million$		50.55 million$
marginal cost =	62.44 mills/kWh		57.71 mills/kWh

delta MC = 4.74 mills/kWh

qf energy = 17298 GWh value = 55.75 million$

TOTAL FUEL SAVINGS

direct plus indirect fuel savings

= 166.87 million$

```
VALUE OF 200 MW BEYOND IDR
         add another 200 MW coal plant to purp08
         calculate additional fuel savings

run#   total cost

purp08    2818.68
purp12    2778.94

            39.74 million$

         compare to direct fuel savings for 500mw

         0.222 million$/MW of fuel saved for 500 MW
         0.199 million$/MW of fuel saved for addl 200 MW

          89.4 %
```

BARE BONES FOR FUEL SAVINGS CALCULATION

SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M$)	
Demand	97022.28	PK Load (MW)	18530.00	Fix O&M	0.00
Unserve	5.77	Capcty (Der.MW)	20117.82	Variable	610.39
Net Gen.	97016.51	Reserve (%)	8.57	Unserved	0.00
Storage	127.77	LOEP (%)	0.006	Fuel	2319.41
Total Gen	97016.51	LOLP (Dys/Yr)	0.135	Total	2929.80

YEAR 1996	Size (MW)	Enrgy (GWH)	Cap fctr	Fixed M$	COSTS O&M M$	Fuel M$	Total M$	Avge mls/kwh	Percent of TOTAL Cap	Energy	Cost
NUCL	2678.	14544.	62.0	0.00	0.00	125.87	125.87	9.	9.47	14.97	4.30
COL1	1636.	8370.	58.4	0.00	0.00	133.55	133.55	16.	5.78	8.62	4.56
COL2	418.	2402.	65.6	0.00	0.00	65.24	65.24	27.	1.48	2.47	2.23
OIL2	0.	0.	0.0	0.00	0.00	0.00	0.00	0.	0.00	0.00	0.00
OIL6	636.	51.	0.9	0.00	0.00	5.70	5.70	112.	2.25	0.05	0.19
GAS	8647.	25125.	33.2	0.00	0.00	1890.89	1890.89	75.	30.57	25.86	64.54
HYDR	10.	2.	2.0	0.00	0.00	0.00	0.00	0.	0.04	0.00	0.00
PURC	6219.	13779.	25.3	0.00	610.39	0.00	610.39	44.	21.99	14.18	20.83
PHYD	4468.	13201.	33.7	0.00	0.00	0.05	0.05	0.	15.80	13.59	0.00
CAES	250.	88.	4.0	0.00	0.00	9.67	9.67	110.	0.88	0.09	0.33
OTH1	2709.	17298.	72.9	0.00	0.00	1.73	1.73	0.	9.58	17.81	0.06
OTH2	450.	1720.	43.6	0.00	0.00	60.55	60.55	35.	1.59	1.77	2.07
PEAK	166.	567.	39.0	0.00	0.00	26.15	26.15	46.	0.59	0.58	0.89

UNSERVED 5.77 GWH DEMAND 97022.28 GWH UNSERVED COST (M$) 0.00

PUMP LOAD 128. NET GENERATION 97017. RESERVE MARGIN 19.09 LOLP 0.13

500 MW COAL FOR FUEL SAVINGS CALCULATIONS

SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M$)	
Demand	97022.04	PK Load (MW)	18530.00	Fix O&M	0.00
Unserve	4.73	Capcty (Der.MW)	20617.82	Variable	568.02
Net Gen.	97017.31	Reserve (%)	11.27	Unserved	0.00
Storage	127.77	LOEP (%)	0.005	Fuel	2250.66
Total Gen	97017.31	LOLP (Dys/Yr)	0.092	Total	2818.68

				C O S T S					Percent of T O T A L		
YEAR 1996	Size (MW)	Enrgy (GWH)	Cap fctr	Fixed M$	O&M M$	Fuel M$	Total M$	Avge mls/kwh	Cap	Energy	Cost
NUCL	2678.	14544.	62.0	0.00	0.00	125.87	125.87	9.	9.30	14.97	4.47
COL1	1636.	8377.	58.5	0.00	0.00	133.61	133.61	16.	5.68	8.62	4.74
COL2	418.	2405.	65.7	0.00	0.00	65.23	65.23	27.	1.45	2.48	2.31
OIL2	500.	2808.	64.1	0.00	0.00	64.87	64.87	23.	1.74	2.89	2.30
OIL6	636.	50.	0.9	0.00	0.00	5.62	5.62	112.	2.21	0.05	0.20
GAS	8647.	23293.	30.8	0.00	0.00	1757.30	1757.30	75.	30.04	23.98	62.34
HYDR	10.	2.	2.0	0.00	0.00	0.00	0.00	0.	0.03	0.00	0.00
PURC	6219.	12793.	23.5	0.00	568.02	0.00	568.02	44.	21.60	13.17	20.15
PHYD	4468.	13200.	33.7	0.00	0.00	0.05	0.05	0.	15.52	13.59	0.00
CAES	250.	88.	4.0	0.00	0.00	9.67	9.67	110.	0.87	0.09	0.34
OTH1	2709.	17297.	72.9	0.00	0.00	1.73	1.73	0.	9.41	17.81	0.06
OTH2	450.	1720.	43.6	0.00	0.00	60.55	60.55	35.	1.56	1.77	2.15
PEAK	166.	567.	39.0	0.00	0.00	26.15	26.15	46.	0.58	0.58	0.93

UNSERVED 4.73 GWH DEMAND 97022.04 GWH UNSERVED COST (M$) 0.00

PUMP LOAD 128. NET GENERATION 97017. RESERVE MARGIN 21.79 LOLP 0.09

BARE BONES WITH 100 MW OF PERFECT CAPACITY FOR MC CALCULATION

SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M$)	
Demand	97021.50	PK Load (MW)	18530.00	Fix O&M	0.00
Unserve	5.56	Capcty (Der.MW)	20217.82	Variable	597.21
Net Gen.	97015.94	Reserve (%)	9.11	Unserved	0.00
Storage	127.77	LOEP (%)	0.006	Fuel	2277.88
Total Gen	97015.94	LOLP (Dys/Yr)	0.118	Total	2875.10

YEAR 1996	Size (MW)	Enrgy (GWH)	Cap fctr	COSTS Fixed M$	O&M M$	Fuel M$	Total M$	Avge mls/kwh	Percent of TOTAL Cap	Energy	Cost
NUCL	2678.	14544.	62.0	0.00	0.00	125.87	125.87	9.	9.43	14.97	4.38
COL1	1636.	8368.	58.4	0.00	0.00	133.54	133.54	16.	5.76	8.61	4.64
COL2	418.	2400.	65.6	0.00	0.00	65.20	65.20	27.	1.47	2.47	2.27
OIL2	100.	876.	****	0.00	0.00	0.00	0.00	0.	0.35	0.90	0.00
OIL6	636.	50.	0.9	0.00	0.00	5.67	5.67	112.	2.24	0.05	0.20
GAS	8647.	24549.	32.4	0.00	0.00	1849.44	1849.44	75.	30.46	25.27	64.33
HYDR	10.	2.	2.0	0.00	0.00	0.00	0.00	0.	0.04	0.00	0.00
PURC	6219.	13481.	24.7	0.00	597.21	0.00	597.21	44.	21.91	13.88	20.77
PHYD	4468.	13201.	33.7	0.00	0.00	0.05	0.05	0.	15.74	13.59	0.00
CAES	250.	88.	4.0	0.00	0.00	9.67	9.67	110.	0.88	0.09	0.34
OTH1	2709.	17298.	72.9	0.00	0.00	1.73	1.73	0.	9.54	17.81	0.06
OTH2	450.	1720.	43.6	0.00	0.00	60.55	60.55	35.	1.59	1.77	2.11
PEAK	166.	567.	39.0	0.00	0.00	26.15	26.15	46.	0.58	0.58	0.91

UNSERVED 5.56 GWH DEMAND 97021.50 GWH UNSERVED COST (M$) 0.00

PUMP LOAD 128. NET GENERATION 97016. RESERVE MARGIN 19.63 LOLP 0.12

500 MW COAL WITH 100 MW PERFECT CAPACITY FOR MC CALCULATION (ALSO CALLED OIL2)

SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M$)	
Demand	97021.32	PK Load (MW)	18530.00	Fix O&M	0.00
Unserve	4.51	Capcty (Der.MW)	20717.82	Variable	555.04
Net Gen.	97016.81	Reserve (%)	11.81	Unserved	0.00
Storage	127.77	LOEP (%)	0.005	Fuel	2213.09
Total Gen	97016.81	LOLP (Dys/Yr)	0.080	Total	2768.13

YEAR 1996	Size (MW)	Enrgy (GWH)	Cap fctr	COSTS Fixed M$	O&M M$	Fuel M$	Total M$	Avge mls/kwh	Percent of TOTAL Cap	Energy	Cost
NUCL	2678.	14544.	62.0	0.00	0.00	125.87	125.87	9.	9.27	14.97	4.55
COL1	1636.	8375.	58.4	0.00	0.00	133.60	133.60	16.	5.66	8.62	4.83
COL2	418.	2403.	65.6	0.00	0.00	65.18	65.18	27.	1.45	2.47	2.35
OIL2	600.	3682.	70.1	0.00	0.00	64.82	64.82	18.	2.08	3.79	2.34
OIL6	636.	50.	0.9	0.00	0.00	5.60	5.60	112.	2.20	0.05	0.20
GAS	8647.	22743.	30.0	0.00	0.00	1719.86	1719.86	76.	29.93	23.41	62.13
HYDR	10.	2.	2.0	0.00	0.00	0.00	0.00	0.	0.03	0.00	0.00
PURC	6219.	12473.	22.9	0.00	555.04	0.00	555.04	44.	21.53	12.84	20.05
PHYD	4468.	13200.	33.7	0.00	0.00	0.05	0.05	0.	15.47	13.59	0.00
CAES	250.	88.	4.0	0.00	0.00	9.67	9.67	110.	0.87	0.09	0.35
OTH1	2709.	17297.	72.9	0.00	0.00	1.73	1.73	0.	9.38	17.81	0.06
OTH2	450.	1720.	43.6	0.00	0.00	60.55	60.55	35.	1.56	1.77	2.19
PEAK	166.	567.	39.0	0.00	0.00	26.15	26.15	46.	0.57	0.58	0.94

UNSERVED 4.51 GWH DEMAND 97021.32 GWH UNSERVED COST (M$) 0.00

PUMP LOAD 128. NET GENERATION 97017. RESERVE MARGIN 22.33 LOLP 0.08

500 MW COAL WITH ADDITIONAL 200 MW COAL FOR VALUE BEYOND IDR

SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M$)	
Demand	97021.89	PK Load (MW)	18530.00	Fix O&M	0.00
Unserve	4.57	Capcty (Der.MW)	20817.82	Variable	550.76
Net Gen.	97017.32	Reserve (%)	12.35	Unserved	0.00
Storage	127.77	LOEP (%)	0.005	Fuel	2228.18
Total Gen	97017.32	LOLP (Dys/Yr)	0.077	Total	2778.94

YEAR 1996	Size (MW)	Enrgy (GWH)	Cap fctr	Fixed M$	COSTS O&M M$	Fuel M$	Total M$	Avge mls/kwh	Percent of TOTAL Cap	Energy	Cost
NUCL	2678.	14544.	62.0	0.00	0.00	125.87	125.87	9.	9.24	14.97	4.53
COL1	1636.	8379.	58.5	0.00	0.00	133.63	133.63	16.	5.64	8.63	4.81
COL2	418.	2406.	65.7	0.00	0.00	65.22	65.22	27.	1.44	2.48	2.35
OIL2	700.	3933.	64.1	0.00	0.00	90.86	90.86	23.	2.41	4.05	3.27
OIL6	636.	50.	0.9	0.00	0.00	5.60	5.60	112.	2.19	0.05	0.20
GAS	8647.	22582.	29.8	0.00	0.00	1708.85	1708.85	76.	29.83	23.25	61.49
HYDR	10.	2.	2.0	0.00	0.00	0.00	0.00	0.	0.03	0.00	0.00
PURC	6219.	12377.	22.7	0.00	550.76	0.00	550.76	44.	21.45	12.74	19.82
PHYD	4468.	13200.	33.7	0.00	0.00	0.05	0.05	0.	15.41	13.59	0.00
CAES	250.	88.	4.0	0.00	0.00	9.67	9.67	110.	0.86	0.09	0.35
OTH1	2709.	17297.	72.9	0.00	0.00	1.73	1.73	0.	9.35	17.81	0.06
OTH2	450.	1720.	43.6	0.00	0.00	60.55	60.55	35.	1.55	1.77	2.18
PEAK	166.	567.	39.0	0.00	0.00	26.15	26.15	46.	0.57	0.58	0.94

UNSERVED 4.57 GWH DEMAND 97021.89 GWH UNSERVED COST (M$) 0.00

PUMP LOAD 128. NET GENERATION 97017. RESERVE MARGIN 22.87 LOLP 0.08

BENCHMARK RESULTS - 1995

SYSTEM REPORT FOR YEAR 1995

ENERGY (GWH)		RELIABILITY		COSTS(M$)	
Demand	93691.88	PK Load (MW)	17894.00	Fix O&M	0.00
Unserve	3.27	Capcty (Der.MW)	20180.04	Variable	570.07
Net Gen.	93688.60	Reserve (%)	12.78	Unserved	0.00
Storage	127.77	LOEP (%)	0.003	Fuel	1812.10
Total Gen	93688.60	LOLP (Dys/Yr)	0.028	Total	2382.17

YEAR 1995	Size (MW)	Enrgy (GWH)	Cap fctr	Fixed M$	O&M M$	COSTS Fuel M$	Total M$	Avge mls/kwh	Percent of TOTAL Cap	Energy	Cost
NUCL	2678.	14544.	62.0	0.00	0.00	121.41	121.41	8.	9.40	15.50	5.10
COL1	1636.	8372.	58.4	0.00	0.00	127.66	127.66	15.	5.75	8.92	5.36
COL2	418.	2310.	63.1	0.00	0.00	57.88	57.88	25.	1.47	2.46	2.43
OIL2	0.	0.	0.0	0.00	0.00	0.00	0.00	0.	0.00	0.00	0.00
OIL6	636.	49.	0.9	0.00	0.00	4.81	4.81	98.	2.23	0.05	0.20
GAS	8647.	20942.	27.6	0.00	0.00	1401.94	1401.94	67.	30.37	22.32	58.85
HYDR	10.	2.	2.0	0.00	0.00	0.00	0.00	0.	0.04	0.00	0.00
PURC	6338.	14181.	25.5	0.00	570.07	0.00	570.07	40.	22.26	15.12	23.93
PHYD	4468.	13200.	33.7	0.00	0.00	0.05	0.05	0.	15.69	14.07	0.00
CAES	250.	88.	4.0	0.00	0.00	9.67	9.67	110.	0.88	0.09	0.41
OTH1	2779.	17842.	73.3	0.00	0.00	8.16	8.16	0.	9.76	19.02	0.34
OTH2	450.	1720.	43.6	0.00	0.00	56.60	56.60	33.	1.58	1.83	2.38
PEAK	166.	567.	39.0	0.00	0.00	23.91	23.91	42.	0.58	0.60	1.00

UNSERVED 3.27 GWH DEMAND 93691.88 GWH UNSERVED COST (M$) 0.00

PUMP LOAD 128. NET GENERATION 93689. RESERVE MARGIN 23.72 LOLP 0.03

4
19
Size for year 1995 1058.00 MW using end-use file : PNW95N.EEM

Month	Maximum Capacity Factor	Cost	Energy Used GWH	Energy Used %	Energy Rejected GWH	Energy Rejected %	Rejection Status Hrs	Max MW	Avg MW
JAN	25.83	44.00	199.47	100.00	0.00	0.00	0	0.00	0.00
FEB	38.69	44.00	298.82	100.00	0.00	0.00	0	0.00	0.00
MAR	20.41	44.00	157.66	100.00	0.00	0.00	0	0.00	0.00
APR	26.06	35.10	201.26	100.00	0.00	0.00	0	0.00	0.00
MAY	27.26	35.10	210.55	100.00	0.00	0.00	0	0.00	0.00
JUN	0.00	35.10	0.00	0.00	0.00	0.00	0	0.00	0.00
JUL	0.00	44.00	0.00	0.00	0.00	0.00	0	0.00	0.00
AUG	0.00	44.00	0.00	0.00	0.00	0.00	0	0.00	0.00
SEP	1.83	44.00	14.10	100.00	0.00	0.00	0	0.00	0.00
OCT	18.82	44.00	145.35	100.00	0.00	0.00	0	0.00	0.00
NOV	17.03	44.00	131.54	100.00	0.00	0.00	0	0.00	0.00
DEC	8.16	44.00	63.02	100.00	0.00	0.00	0	0.00	0.00
Annual	15.34	41.42	1421.76	100.00	0.00	0.00	0	0.00	0.00

19
Size for year 1995 1286.00 MW using end-use file : SW95N.EEM

Month	Maximum Capacity Factor	Cost	Energy Used GWH	Energy Used %	Energy Rejected GWH	Energy Rejected %	Rejection Status Hrs	Max MW	Avg MW
JAN	32.31	48.30	303.32	100.00	0.00	0.00	0	0.00	0.00
FEB	21.06	48.30	197.66	100.00	0.00	0.00	0	0.00	0.00
MAR	19.41	48.30	182.19	100.00	0.00	0.00	0	0.00	0.00
APR	20.55	48.30	192.90	100.00	0.00	0.00	0	0.00	0.00
MAY	38.69	48.30	363.22	100.00	0.00	0.00	0	0.00	0.00
JUN	19.83	48.30	186.21	100.00	0.00	0.00	0	0.00	0.00
JUL	19.27	48.30	180.88	100.00	0.00	0.00	0	0.00	0.00
AUG	16.63	48.30	156.12	100.00	0.00	0.00	0	0.00	0.00
SEP	17.99	48.30	168.85	100.00	0.00	0.00	0	0.00	0.00
OCT	27.26	48.30	255.89	100.00	0.00	0.00	0	0.00	0.00
NOV	13.06	48.30	122.59	100.00	0.00	0.00	0	0.00	0.00
DEC	22.65	48.30	212.66	100.00	0.00	0.00	0	0.00	0.00
Annual	22.39	48.30	2522.50	100.00	0.00	0.00	0	0.00	0.00

19
Size for year 1995 2269.00 MW using end-use file : SW95F.EEM

Month	Maximum Capacity Factor	Cost	Energy Used GWH	Energy Used %	Energy Rejected GWH	Energy Rejected %	Rejection Status Hrs	Max MW	Avg MW
JAN	49.35	36.60	817.34	96.98	25.43	3.02	78	962.86	325.11
FEB	30.65	36.60	507.74	81.38	116.19	18.62	182	1394.07	636.65
MAR	30.51	36.60	505.42	73.85	178.93	26.15	247	1529.08	722.44
APR	28.74	36.60	476.02	60.84	306.33	39.16	308	1748.04	992.94
MAY	39.57	36.60	655.38	64.54	360.13	35.46	299	2269.00	1201.16
JUN	33.09	36.60	548.15	73.96	193.00	26.04	221	1834.03	870.90
JUL	29.69	36.60	491.76	94.04	31.16	5.96	60	1177.29	512.23
AUG	30.52	36.60	505.47	96.14	20.29	3.86	56	798.06	359.22
SEP	31.30	36.60	518.49	66.62	259.79	33.38	238	1925.93	1087.06

OCT	30.08	36.60	498.20	57.55	367.43	42.45	295	1934.10	1243.51
NOV	36.88	36.60	610.79	97.13	18.02	2.87	69	652.56	259.14
DEC	31.52	36.60	522.04	79.34	135.91	20.66	195	1470.09	695.07
Annual	33.49	36.60	6656.79	76.78	2012.62	23.22	2255	2269.00	892.44

19
Size for year 1995 1725.00 MW using end-use file : BAD95F.EEM

Month	Maximum Capacity Factor	Cost	Energy Used GWH	%	Energy Rejected GWH	%	Rejection Status Hrs	Max MW	Avg MW
JAN	4.15	44.00	52.30	90.20	5.68	9.80	43	151.63	130.70
FEB	33.95	44.00	427.57	68.61	195.60	31.39	139	1629.78	1406.74
MAR	38.91	44.00	490.01	69.16	218.47	30.84	152	1659.62	1436.53
APR	29.63	35.10	373.07	63.68	212.77	36.32	169	1532.15	1255.57
MAY	40.05	35.10	504.34	67.78	239.72	32.22	212	1570.96	1125.87
JUN	32.58	35.10	410.31	67.94	193.58	32.06	139	1610.46	1392.21
JUL	38.56	44.00	485.51	84.38	89.85	15.62	104	1628.23	861.54
AUG	34.95	44.00	440.08	81.54	99.60	18.46	108	1725.00	916.89
SEP	7.25	44.00	91.27	64.34	50.59	35.66	112	453.33	447.77
OCT	11.97	44.00	150.77	66.84	74.78	33.16	130	589.78	573.69
NOV	9.49	44.00	119.48	84.31	22.23	15.69	82	370.70	269.29
DEC	2.78	44.00	35.03	73.36	12.72	26.64	108	124.89	117.11
Annual	23.69	40.80	3579.74	71.66	1415.60	28.34	1503	1725.00	941.57

assumptions used to calculate the 1995 cost of

500 mw generic coal plant
combustion turbine proxy
fuel use for the coal plant

data source: sce cfm vi supply plan, july, 1985

capital cost from Form R-10

coal plant 500 MW	1614	1982$/kW
comb turb	381	
energy related cap	1233	

generation construction cost escalation
(includes inflation) from Form R-18 to 1987, 6% thereafter

1983	5.0 %/yr	1.05
1984	4.0	1.04
1985	6.0	1.06
1986	6.0	1.06
1987	6.0	1.06
1988	6.0	1.06
1989	6.0	1.06
1990	6.0	1.06
1991	6.0	1.06
1992	6.0	1.06
1993	6.0	1.06
1994	6.0	1.06
1995	6.0	1.06

escalation factor 2.07 (83-95)

1995 energy-related capital cost 2555.9 1995$/kW ct cost 789.8

calculations for revenue requirements spreadsheets

ratebase(i) = ratebase(i+1) - depreciation(i+1)

required return = ratebase * fixed charge rate

revenue requirements = required return + depreciation

fixed charge rate	22.9	from Form R-11
depreciation	straight-line	
lifetime	35	from Form R-11
discount rate	13.3	from Form R-11

revenue requirements for the energy-related capital component of
the coal plant identified deferrable resource

year	ratebase	deprecia	req ret	rev req	pv@13.3	eccr (5%) 0.078319	delta .0000
1995	2555.9	73.0	585.3	658.3	658.3	355.9	355.9
1996	2482.9	73.0	568.6	641.6	566.3	373.7	329.8
1997	2409.9	73.0	551.9	624.9	486.8	392.3	305.6
1998	2336.9	73.0	535.1	608.2	418.2	412.0	283.2
1999	2263.8	73.0	518.4	591.4	358.9	432.6	262.5
2000	2190.8	73.0	501.7	574.7	307.8	454.2	243.3
2001	2117.8	73.0	485.0	558.0	263.8	476.9	225.4
2002	2044.8	73.0	468.2	541.3	225.8	500.7	208.9
2003	1971.7	73.0	451.5	524.6	193.2	525.8	193.6
2004	1898.7	73.0	434.8	507.8	165.1	552.1	179.4
2005	1825.7	73.0	418.1	491.1	140.9	579.7	166.3
2006	1752.6	73.0	401.4	474.4	120.1	608.6	154.1
2007	1679.6	73.0	384.6	457.7	102.3	639.1	142.8
2008	1606.6	73.0	367.9	440.9	87.0	671.0	132.4
2009	1533.6	73.0	351.2	424.2	73.9	704.6	122.7
2010	1460.5	73.0	334.5	407.5	62.6	739.8	113.7
2011	1387.5	73.0	317.7	390.8	53.0	776.8	105.3
2012	1314.5	73.0	301.0	374.0	44.8	815.6	97.6
2013	1241.5	73.0	284.3	357.3	37.8	856.4	90.5
2014	1168.4	73.0	267.6	340.6	31.8	899.2	83.9
2015	1095.4	73.0	250.8	323.9	26.7	944.2	77.7
2016	1022.4	73.0	234.1	307.2	22.3	991.4	72.0
2017	949.3	73.0	217.4	290.4	18.6	1041.0	66.7
2018	876.3	73.0	200.7	273.7	15.5	1093.0	61.9
2019	803.3	73.0	184.0	257.0	12.8	1147.7	57.3
2020	730.3	73.0	167.2	240.3	10.6	1205.1	53.1
2021	657.2	73.0	150.5	223.5	8.7	1265.3	49.2
2022	584.2	73.0	133.8	206.8	7.1	1328.6	45.6
2023	511.2	73.0	117.1	190.1	5.8	1395.0	42.3
2024	438.2	73.0	100.3	173.4	4.6	1464.8	39.2
2025	365.1	73.0	83.6	156.6	3.7	1538.0	36.3
2026	292.1	73.0	66.9	139.9	2.9	1614.9	33.7
2027	219.1	73.0	50.2	123.2	2.3	1695.7	31.2
2028	146.1	73.0	33.4	106.5	1.7	1780.4	28.9
2029	73.0	73.0	16.7	89.7	1.3	1869.5	26.8
2030	.0	73.0	.0	73.0	0.9	1962.9	24.8
					4543.7		4543.7

first year eccr times capital cost 355.9 1995$/kW
for a 500MW plant 177.9 million 1995 $

revenue requirements for the combustion turbine proxy

year	ratebase	deprecia	req ret	rev req	pv@13.3	eccr (5%) 0.078319	delta .0000
1995	789.8	22.6	180.9	203.4	203.4	110.0	110.0
1996	767.2	22.6	175.7	198.3	175.0	115.5	101.9
1997	744.7	22.6	170.5	193.1	150.4	121.2	94.4
1998	722.1	22.6	165.4	187.9	129.2	127.3	87.5
1999	699.5	22.6	160.2	182.8	110.9	133.7	81.1
2000	677.0	22.6	155.0	177.6	95.1	140.3	75.2
2001	654.4	22.6	149.9	172.4	81.5	147.4	69.7
2002	631.8	22.6	144.7	167.3	69.8	154.7	64.6
2003	609.3	22.6	139.5	162.1	59.7	162.5	59.8
2004	586.7	22.6	134.4	156.9	51.0	170.6	55.4
2005	564.1	22.6	129.2	151.8	43.5	179.1	51.4
2006	541.6	22.6	124.0	146.6	37.1	188.1	47.6
2007	519.0	22.6	118.9	141.4	31.6	197.5	44.1
2008	496.4	22.6	113.7	136.3	26.9	207.4	40.9
2009	473.9	22.6	108.5	131.1	22.8	217.7	37.9
2010	451.3	22.6	103.3	125.9	19.3	228.6	35.1
2011	428.7	22.6	98.2	120.7	16.4	240.0	32.6
2012	406.2	22.6	93.0	115.6	13.8	252.0	30.2
2013	383.6	22.6	87.8	110.4	11.7	264.6	28.0
2014	361.0	22.6	82.7	105.2	9.8	277.9	25.9
2015	338.5	22.6	77.5	100.1	8.2	291.8	24.0
2016	315.9	22.6	72.3	94.9	6.9	306.4	22.3
2017	293.4	22.6	67.2	89.7	5.8	321.7	20.6
2018	270.8	22.6	62.0	84.6	4.8	337.8	19.1
2019	248.2	22.6	56.8	79.4	4.0	354.6	17.7
2020	225.7	22.6	51.7	74.2	3.3	372.4	16.4
2021	203.1	22.6	46.5	69.1	2.7	391.0	15.2
2022	180.5	22.6	41.3	63.9	2.2	410.5	14.1
2023	158.0	22.6	36.2	58.7	1.8	431.1	13.1
2024	135.4	22.6	31.0	53.6	1.4	452.6	12.1
2025	112.8	22.6	25.8	48.4	1.1	475.3	11.2
2026	90.3	22.6	20.7	43.2	0.9	499.0	10.4
2027	67.7	22.6	15.5	38.1	0.7	524.0	9.6
2028	45.1	22.6	10.3	32.9	0.5	550.2	8.9
2029	22.6	22.6	5.2	27.7	0.4	577.7	8.3
2030	.0	22.6	.0	22.6	0.3	606.6	7.7
					1404.0		1404.0

first year eccr times capital cost 110.0 1995$/kW
for a 500MW plant 55.0 million 1995 $

coal fuel price escalation

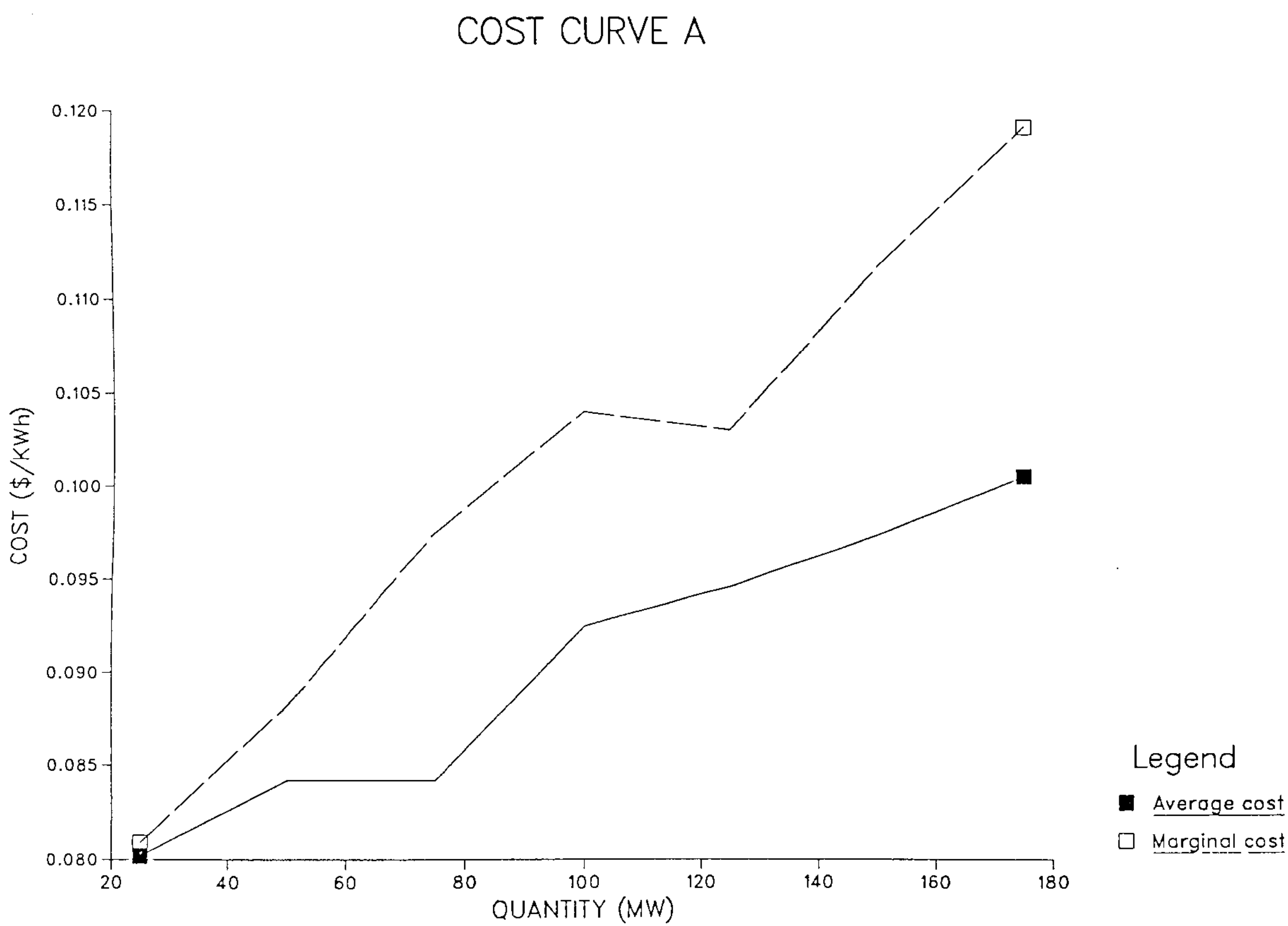
	price	escal		pv@13.3
1995	2.00			2.00
1996	2.20	10.0		1.94
1997	2.30	4.5		1.79
1998	2.50	8.7		1.72
1999	2.60	4.0		1.58
2000	2.70	3.8		1.45
2001	2.90	7.4		1.37
2002	3.10	6.9		1.29
2003	3.30	6.5		1.22
2004	3.60	9.1		1.17
2005	3.70	2.8	6.5	1.06
2006	3.94	6.5		1.00
2007	4.20	6.5		0.94
2008	4.47	6.5		0.88
2009	4.76	6.5		0.83
2010	5.07	6.5		0.78
2011	5.40	6.5		0.73
2012	5.75	6.5		0.69
2013	6.13	6.5		0.65
2014	6.52	6.5		0.61
2015	6.95	6.5		0.57
2016	7.40	6.5		0.54
2017	7.88	6.5		0.51
2018	8.39	6.5		0.47
2019	8.94	6.5		0.45
2020	9.52	6.5		0.42
2021	10.14	6.5		0.39
2022	10.80	6.5		0.37
2023	11.50	6.5		0.35
2024	12.25	6.5		0.33
2025	13.05	6.5		0.31
2026	13.90	6.5		0.29
2027	14.80	6.5		0.27
2028	15.76	6.5		0.26
2029	16.79	6.5		0.24
2030	17.88	6.5		0.23
				29.7 1995$/mbtu

present value of fuel over 35 yr 887.2 million 1995 $
500mw, 10500 heat rate, 65% cf

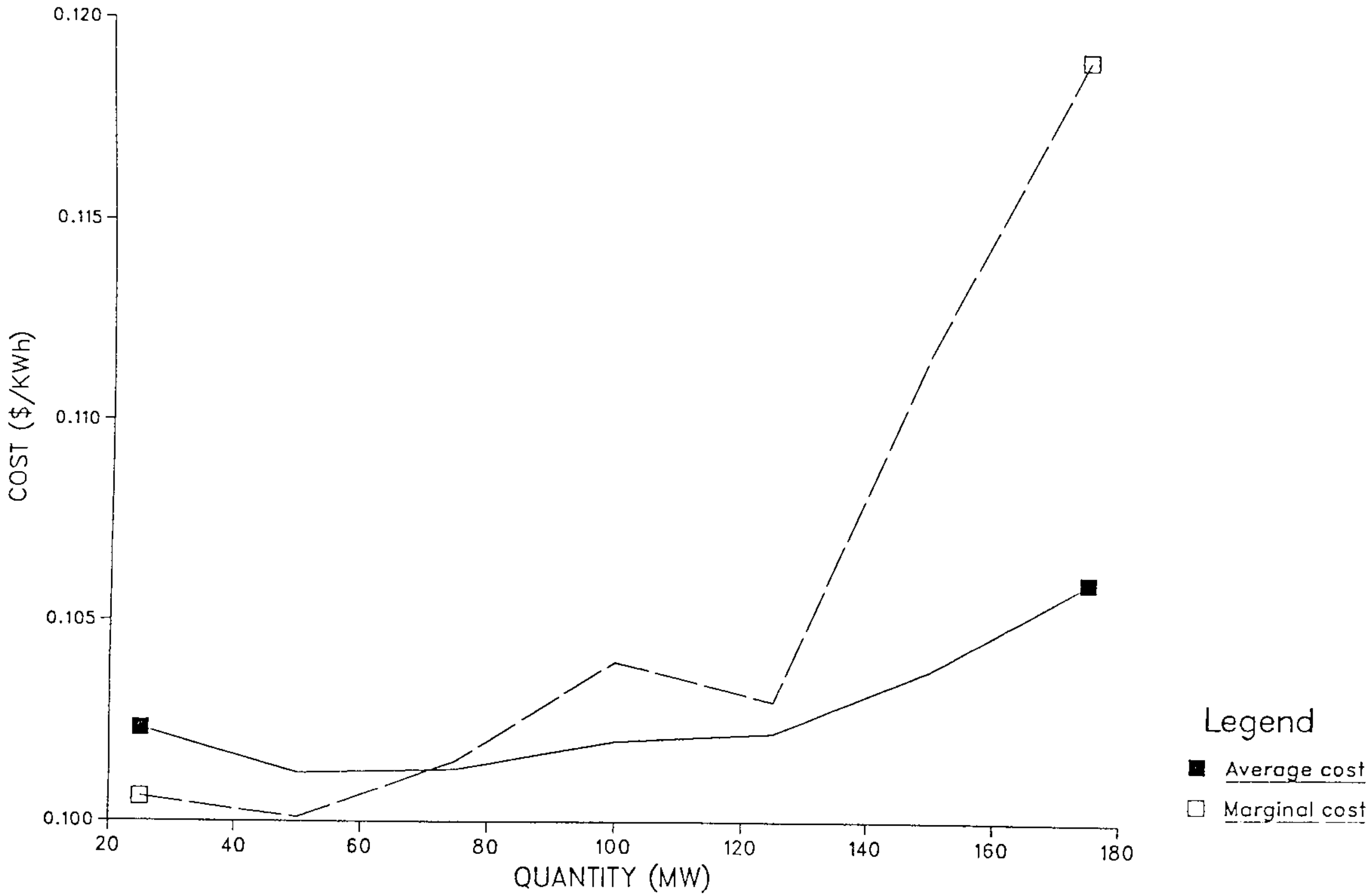
total present value of coal plant 3861.1 million 1995 $
= energy-related cap + comb turbine + fuel

total times eccr	302.4 million 1995 $ 106.2 mills/kWh (65% cf)
levelized annual cost 13.3 disc rate, 5.0 gen infl	168.4 mills/kWh (65% cf)

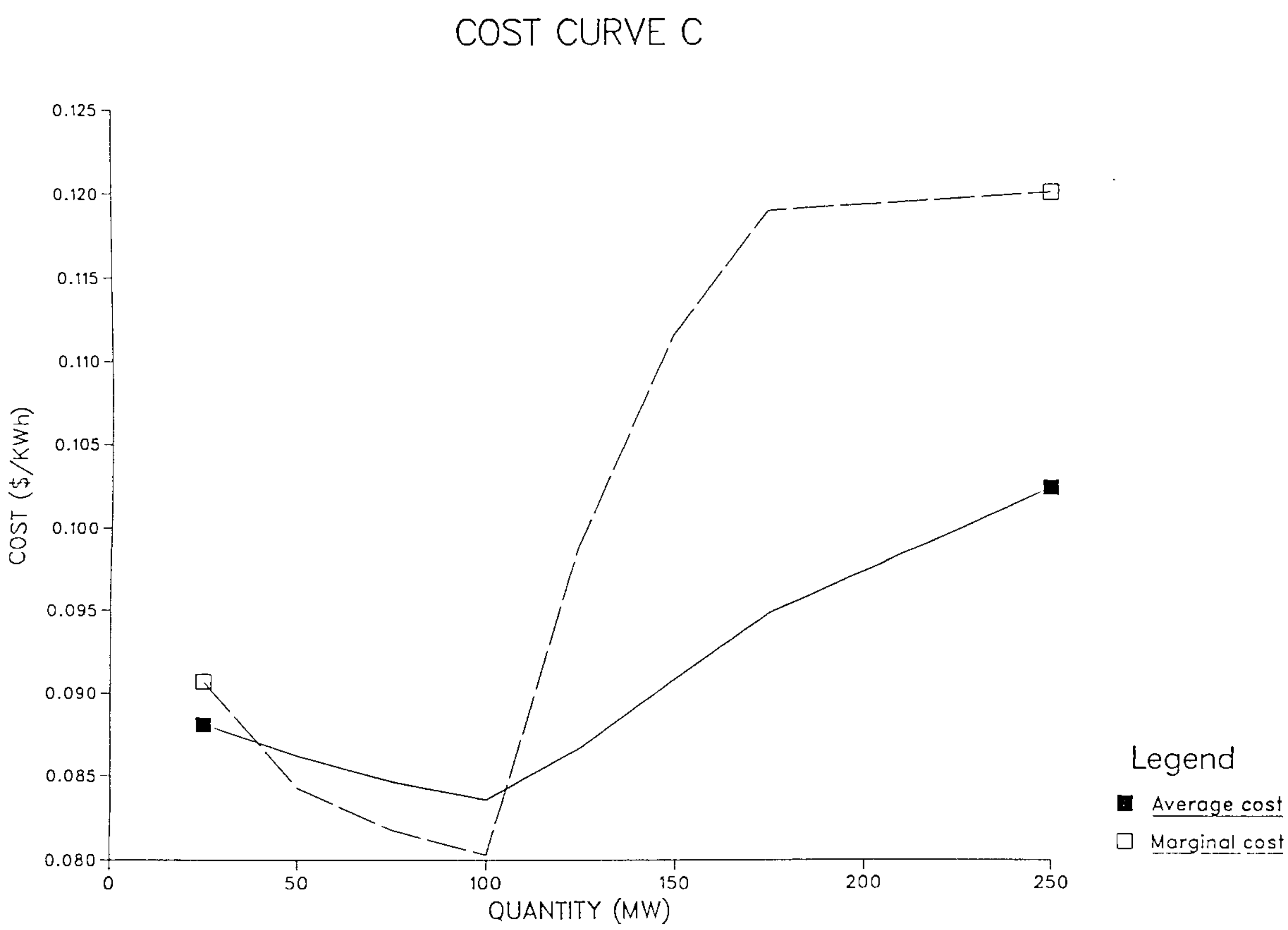
```
k =        0.926743
a sub n =7.423714
l sub n =1.585210
```


COST CURVE A
COST ($/KWh)
0.120
0.115
0.110
0.105
0.100
0.095
0.090
0.085
0.080
20
40
60
80
100
120
140
160
180
QUANTITY (MW)
Legend
Average cost
Marginal cost

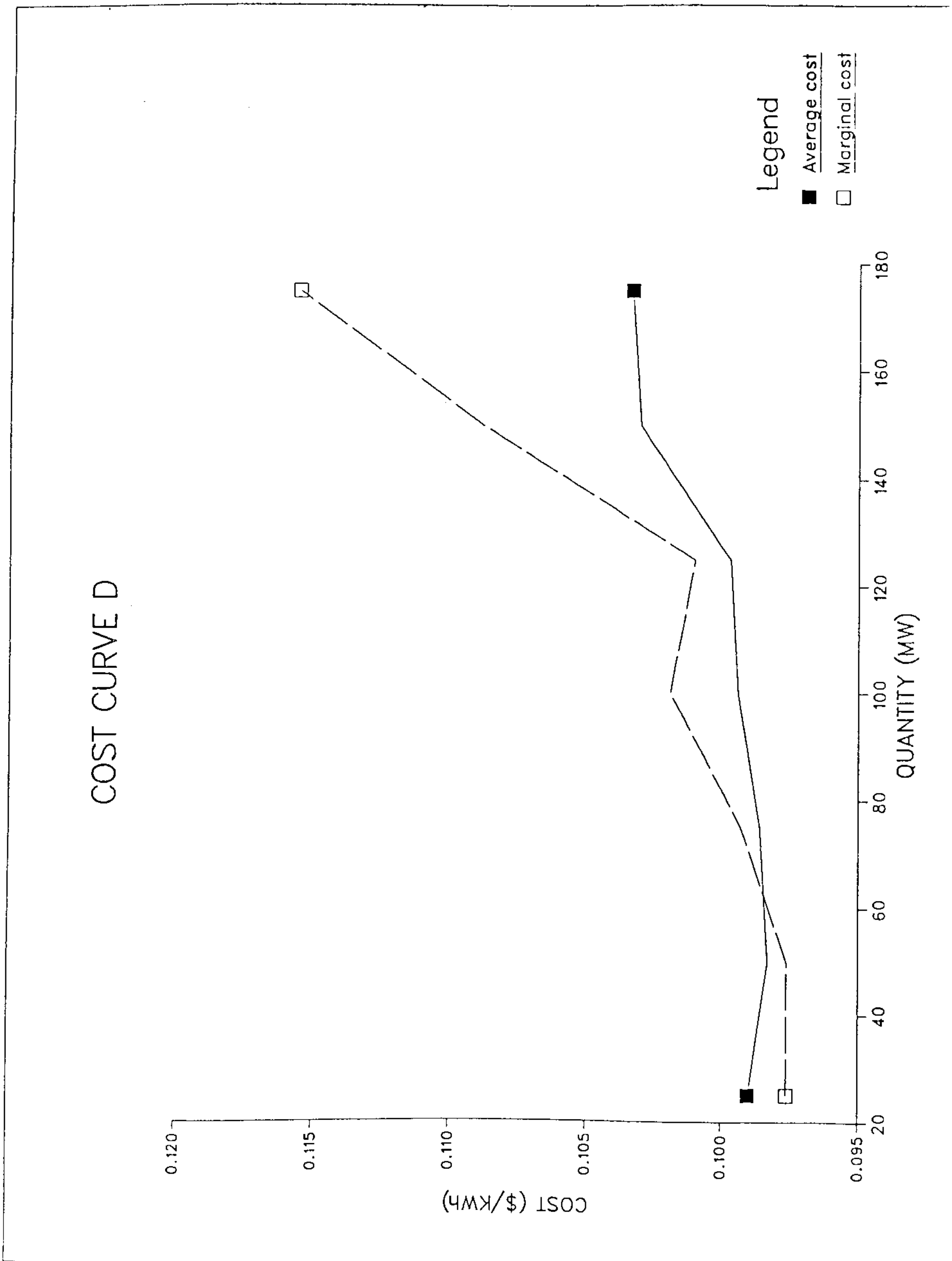
COST CURVE B

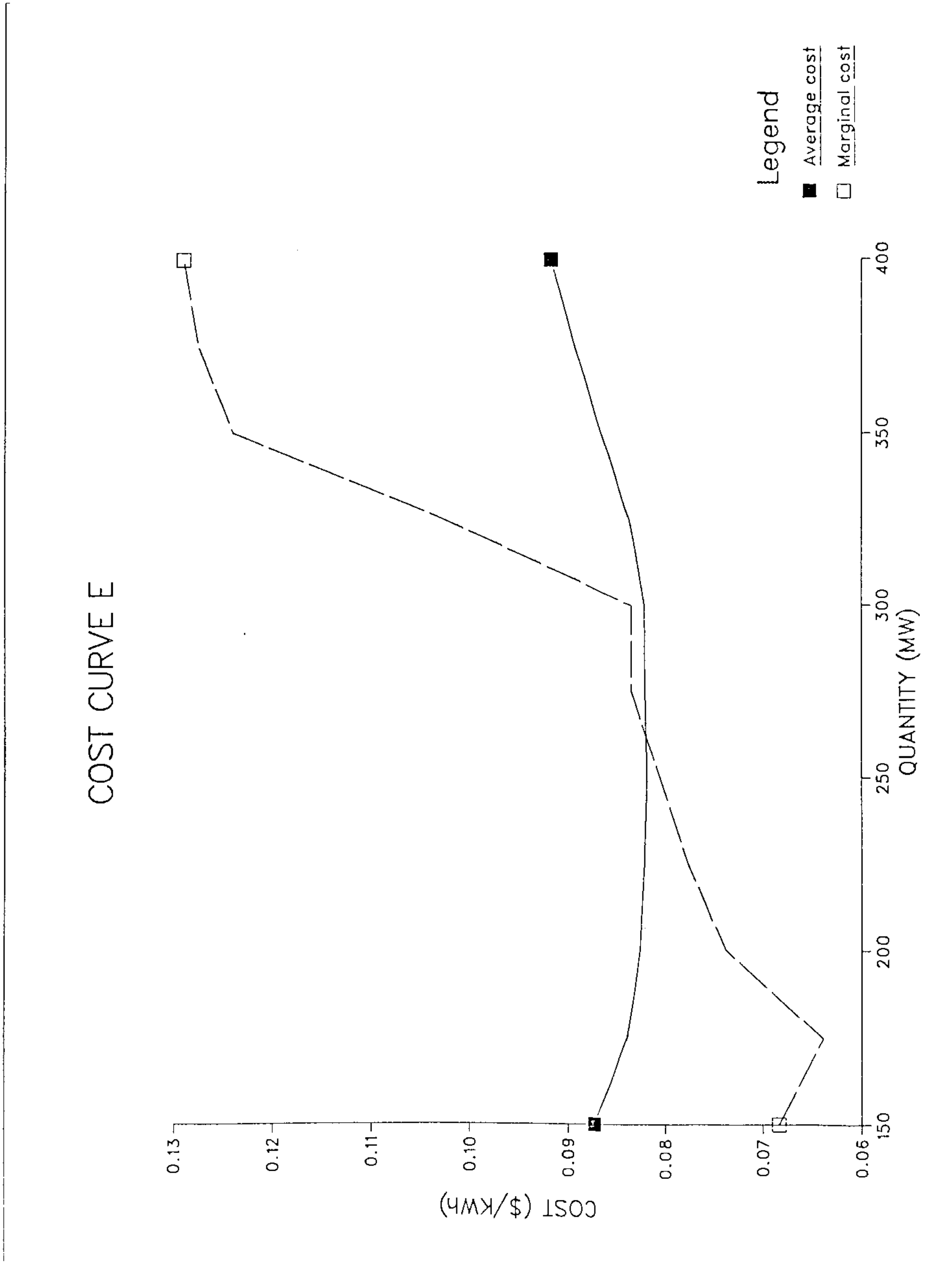


0.120
0.115
0.110
0.105
0.100
COST ($/KWh)
20
40
60
80
100
120
140
160
180
QUANTITY (MW)
Legend
Average cost
Marginal cost



COST CURVE C
COST ($/KWh)
0.125
0.120
0.115
0.110
0.105
0.100
0.095
0.090
0.085
0.080
0
50
100
150
200
250
QUANTITY (MW)
Legend
Average cost
Marginal cost


COST CURVE D
COST ($/KWh)
0.095
0.100
0.105
0.110
0.115
0.120
QUANTITY (MW)
20
40
60
80
100
120
140
160
180
Legend
Average cost
Marginal cost



COST CURVE E
COST ($/KWh)
0.13
0.12
0.11
0.10
0.09
0.08
0.07
0.06
QUANTITY (MW)
150
200
250
300
350
400
Legend
Average cost
Marginal cost

Appendix I

An Example of Cost Difference Diminution Resulting from Price Misestimation

In classical bidding theory, economic inefficiency in a first price auction arises from the possibility that a bidder with a lower cost will overestimate the price necessary to win and, hence, will bid higher than and lose to a bidder with a higher cost. Classical theory does not contemplate that a bidder's cost will be affected by its price estimate. This, however, is the case in PURPA auctions in which a bidder uses its price estimate both to select the quantity to offer and to select its bid. Section 3.5 of the main body of this report discusses the fact that the economic inefficiencies of first price auctions can be diminished or even eliminated by the interaction of the price estimation process with the capacity determination process. This appendix offers a specific quantitative example of this effect.

Consider two bidders with quadratic marginal cost curves that differ by a constant. Let Bidder 1 have marginal cost curve

$$MC_1 = ax_1^2 + bx_1 + c,$$

where a, b, and c are constants and x_1 is the quantity produced by Bidder 1. For any capacity, x_2, Bidder 2's marginal cost is higher by a constant d. Hence,

$$MC_2 = ax_2^2 + bx_2 + c + d.$$

By integrating these marginal costs (and for simplicity assuming that the constant of integration is zero), we obtain the bidders' total costs and by dividing the costs by the quantity produced, we find their average costs per unit:

$$C_1(x_1) = ax_1^3/3 + bx_1^2/2 + cx_1,$$

$$C_2(x_2) = ax_2^3/3 + bx_2^2/2 + (c+d)x_2,$$

$$AC_1(x_1) = ax_1^2/3 + bx_1/2 + c,$$

and

$$AC_2(x_2) = ax_2^2/3 + bx_2/2 + c + d.$$

Note that the bidder's average unit costs also differ by the constant d.

If Bidder 1 expects unit price P_1 and Bidder 2 expects unit price P_2, the optimum quantities for them to bid, x_1^* and x_2^* respectively, are found by setting their marginal costs equal to their price expectations. The solutions of these equations are given by

$$x_1^* = [-b + \sqrt{b^2 - 4a(c - P_1)}]/2a,$$

and

$$x_2^* = [-b + \sqrt{b^2 - 4a(c + d - P_2)}]/2a.$$

The difference in the bidders' average cost per unit, Δ, can be calculated as

$$\begin{aligned}\Delta &= AC_2(x_2^*) - AC_1(x_1^*)\\ &= 2d/3 - (P_1 - P_2)/3 + [\sqrt{b^2 - 4a(c + d - P_2)} - \sqrt{b^2 - 4a(c - d - P_1)}]\, b/12a.\end{aligned}$$

Note that if $P_1 = P_2$ and d=0, Δ=0 too.

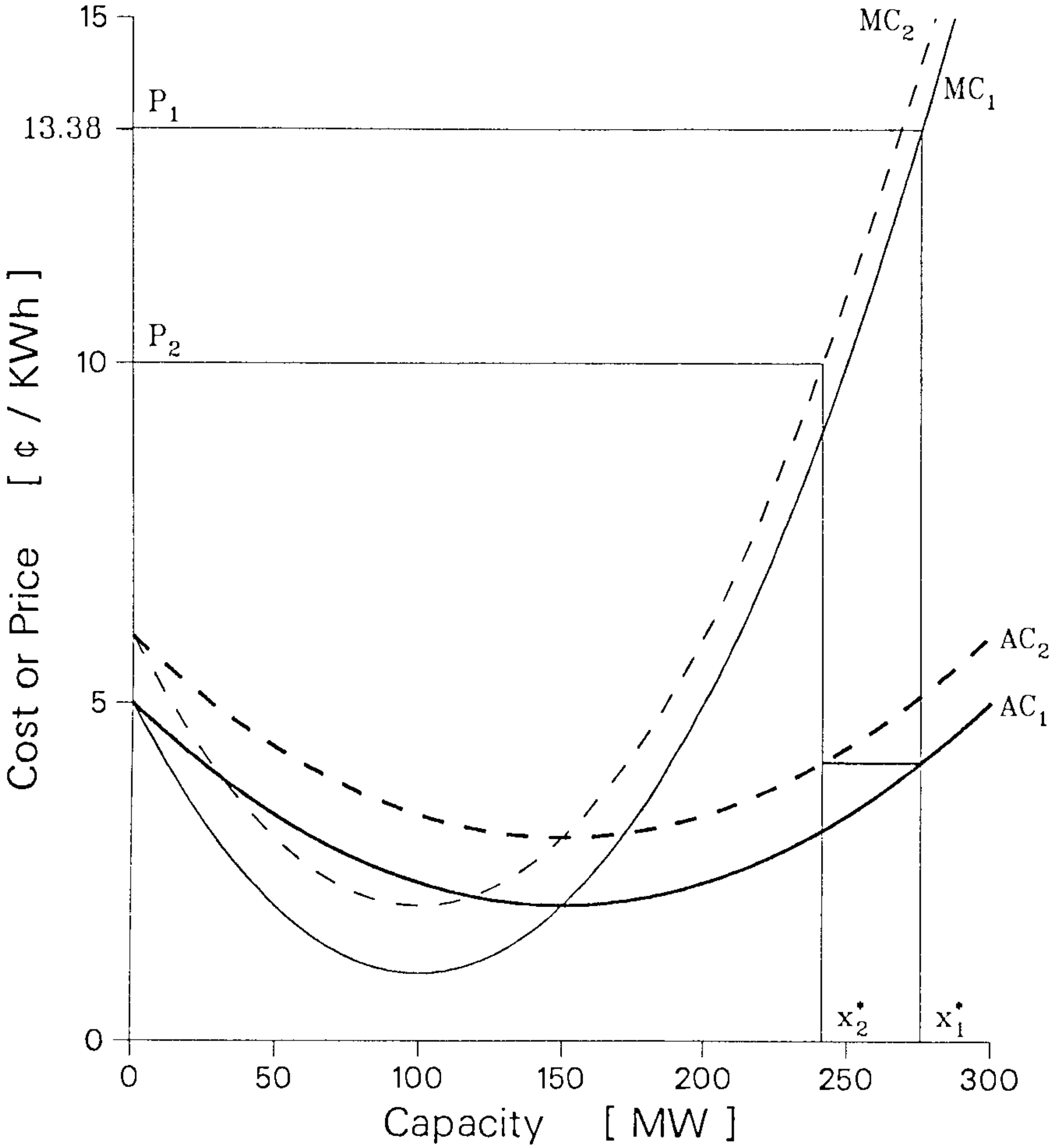
We now give some numerical results for some of these quantities for an example in which a =.0004, b=-.08, c=5, and d=1. This results in a marginal cost for Bidder 1 that starts at 5, falls to a minimum of 1 at a capacity of 100, and then rises and one for Bidder 2 that is one unit higher. Figure I-1 illustrates these marginal cost curves and the associated average unit cost curves.

The first case of interest is one in which both bidders expect the same unit price, $P_1 = P_2 = 10$. In this case, Bidder 1 selects a capacity of 250, while Bidder 2, because of its higher costs, selects a smaller capacity of approximately 241.4. This smaller capacity for Bidder 2 results in an average unit cost of 4.114, which is higher than Bidder 1's average unit cost but by only .781, not the full unit difference between their average unit costs at any given capacity.

If Bidder 1 with the lower cost curve anticipates a higher price than 10, then it will increase its capacity and raise its average cost. If it anticipates a unit price of 12, it will increase its capacity to 265.8 and the difference in average costs will fall to rise to 275.9 and the cost difference will vanish completely. This case is illustrated in Figure I-1. For any higher price estimate, Bidder 1 with the lower cost curve is actually the bidder with the higher unit cost. If this happens, economic efficiency will be increased by its loss of the auction.

Figure I–1

Cost Curves, Anticipated Prices, and Capacities



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