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WELFARE AND EFFICIENCY BENEFITS OF ALL SOURCES BIDDING

Author
Kahn, E.

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Lawrence Berkeley Laboratory

UNIVERSITY OF CALIFORNIA

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Welfare and Efficiency Benefits of All Sources Bidding

E. Kahn

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Edward Kahn

Applied Science Division
Lawrence Berkeley Laboratory
1 Cyclotron Road
Berkeley, California 94720

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EXECUTIVE SUMMARY

This study analyzes the welfare and efficiency benefits of the Federal Energy Regulatory Commission's (FERC) recent Notice of Proposed Rulemaking (NOPR) on bidding and independent power producers. FERC has proposed regulatory guidelines that will involve reduced regulation for a class of wholesale generation suppliers known as Independent Power Producers (IPPs). The essence of the FERC proposals is that IPPs be part of competitive bidding processes for new electric generation; hence the term "all sources bidding."

What kind of technologies would emerge in the event that the FERC NOPRs were implemented? Several utilities have argued that IPPs would consist largely of gas-fired combustion turbines because IPPs will be capital-minimizers. Many other analysts believe that coal-fired technologies will emerge as the dominant class, principally because of innovative technology possibilities (e.g., "clean-coal") that are in the early commercialization stages (and thus have higher risks), yet have the potential of achieving low production costs while meeting environmental standards. The dominant position obtained by a particular generating technology and fuel type often hinges on regulatory factors. For example, the specification of contract lengths has a major impact on the fuel choices of suppliers. Because of relative differences in capital intensity and the requirement to amortize over appropriate periods, long-term contracts that can be signed for 20 years or more favor coal projects, while contracts that are limited to 10 years favor gas-fired cogeneration projects. The FERC NOPRs should produce a class of suppliers that offer more diversity with respect to operational characteristics than Qualified Facilities (QFs), because there is no obligation to purchases from IPPs. Because of this obligation, QFs have typically operated as baseload producers, rather than as load-following or dispatchable suppliers. Many utilities will want IPPs to be dispatchable, although it is unlikely that the value of dispatchability can be predicted adequately at the outset of a bid solicitation. Thus, this is one of the areas in which it is likely that there will be a role for subsequent negotiations under any regulatory regime.

Alternative Views of the Prospects for Electric Utility Regulation

Given these assumptions about the operating characteristics of likely generating technologies, we then developed an approach that compared the effect of the FERC NOPRs relative to some scenario of events absent the changes. However, there is widespread disagreement about the future prospects for electric utility regulation. Thus, we developed three alternative scenarios that reflect the diversity of views on the status of the regulatory environment. These three characterizations served as "baselines" against which the FERC proposals were evaluated. The key features of each scenario are:

- Baseline #1: Capital Minimization - Utilities go to great lengths to avoid or defer capital investment in new generation because of a hostile regulatory enviroment. Utilities will satisfy their obligation to serve by relying heavily on either short- or long-term purchase agreements, investing in combustion turbines as a last resort.

- Baseline #2: Joint Responsibility with Rolling Prudency Review - This scenario is based on a concept of regulatory reform that emphasizes shared responsibility between utility management and regulatory authorities. Resource planning is done on a joint basis with the explicit understanding that prudency reviews will be periodic, but will not impact cost recovery. The paradigm of shared responsibility is advocated both by proponents of increased emphasis on demand-side management (DSM) and by advocates of increased supply-side construction by utilities under rate of return regulation.
- Baseline #3: Optimal Risk Aversion - The fundamental assumption of this scenario is that the regulatory upheavals of the 1970s and 1980s have made no really permanent change in the industry environment. Exogenous shocks and management errors of the past may have induced a more appropriate risk aversion, but neither the retreat from investment, nor the shared responsibility characteristic of scenarios #1 and #2 represent a real long-run equilibrium. Utilities retain monopoly power and will invest in new capacity when appropriate. Management assumes its traditional planning function and bears the risks of its investment choices. The function of regulation is to restrain that market power, and not cross the line into centralized government planning.

Welfare and Efficiency Benefits and Transaction Costs of All-Source Bidding

Under scenario #1, the FERC NOPR produces significant benefits. This occurs as much because of the unsatisfactory state of affairs absent the NOPRs as because of the unmitigated benefits of bidding and IPPs. Added competition from IPPs will have the effect of reducing economic rents to QFs. Because utility management is pursuing a capital minimization strategy, incremental supply will depend on complex contracts with QFs and IPPs. Even though there is no obligation to purchase from IPPs, some "take-or-pay" terms can be expected. On the cost side, there will be some increase in transaction costs under scenario #1 (e.g., principally the on-going costs of contract compliance and costs associated with project failure) and dispatchability will likely be a continuing problem. The outcome in terms of dispatchable power will be less efficient in this scenario than in others because the utility is not a credible alternative to provide incremental dispatchability. Combustion turbines, the only utility option, are not a true load-following resource; their efficiency at part load operation is typically quite poor. However, all sources bidding will be a welfare improvement as long as IPP prices stay below combustion turbine power costs. On balance, the expected benefits in Scenario #1 would probably exceed the increased transaction costs.

Under scenario #2, IPPs can be expected to have less bargaining power compared to scenario #1. There will be less need to provide favorable contract terms because the utility's construction program is a credible alternative to QF, IPP, or purchased power. This may not eliminate "take or pay" clauses, but it should reduce their role. It is also likely that there would be less IPP development in this scenario compared to scenario #1, because regulated utility generation offers another competitive option. On the cost side, the inflexibilities associated with IPP contracts may be greater in scenario #2 compared to scenario #1 because there will not be an opportunity for a mid-course correction (''rolling prudency'' reviews). For example, if the shared planning process results in an over-estimate of supply requirements, only the utility project will be cancellable, and not the IPP contract. However, dispatchability should be less of a problem in scenario #2, because the utilities will compete with private producers to serve intermediate load. The balance of costs and benefits of the FERC NOPRs is more narrow in Baseline #2 than in Baseline #1. The trade-off boils down to weighing the advantages of potential innovation and competition from new players against the inflexibilities of IPP contracts. In summary, the shared responsibility regulatory paradigm has the virtue of keeping the presence of a regulated supply capability at the cost of shifting adjustment burdens to the consumer.

From the perspective of scenario #3, the PURPA experience is not an unmitigated success. It amounts to a regulatory attempt to ''manage'' competition, which is doomed to counterproductive failure. In many cases, long-term contracts offered to QFs were urged on utilities by the regulatory commissions without due regard to appropriate price and/or quantity restrictions. Thus, FERC's attempts to reform PURPA (i.e., bidding systems) are a potentially positive development. However, from this perspective, PURPA-like reforms suffer from chronic problems insofar as they create politically potent constituencies that can exercise market power. This constituency has its political entitlement embedded in the obligation to purchase placed on the utility and has lobbied for long-term contracts that granted substantial economic and political power to the "QF industry." From this perspective, the FERC NOPRs are another step toward the creation of a special economic interest of favored producers.

The task of regulation will become more difficult as the industry implements the reforms envisaged by the FERC NOPRs because the complexities of contracting are added to the problems of resource planning. Whether this change represents an overall improvement in welfare and efficiency depends upon one's view of the prospects for regulation in the absence of these initiatives. The benefits of all sources bidding are generally greatest where the failures of regulation are large. There will be differences in bargaining power and flexibility depending on the degree of competition between IPPs and regulated suppliers. Efficiency gains will be obtained, but at the price of higher transaction costs. It is less clear whether these costs will be large. On balance the FERC proposals appear beneficial.

1. INTRODUCTION

This study examines the impact of competitive bidding for new generating capacity on the electric utility industry. Competitive bidding for new generating capacity is a reform of the regulatory process designed to improve the efficiency of electricity production. Individual states have experimented with a number of schemes which aim at improving efficiency incentives (Joskow & Schmalensee, 1986). The bidding approach has been taken up at the federal level as well as by particular states. To make the analysis concrete, we focus on the impact of the Notices of Proposed Rulemaking (NOPR) issued by the Federal Energy Regulatory Commission (FERC) in March 1988 on bidding and independent power producers. In the two NOPRs, FERC proposes guidelines for power purchase auctions that will also involve reduced regulation for a class of wholesale generation suppliers known as Independent Power Producers (IPPs). IPPs are defined as entities that are selling from facilities that are not regulated on a cost-of-service basis, that do not control transmission facilities essential to the buyer, and, if they are a franchised utility, are selling to buyers outsider their retail service territory. The essence of the FERC proposals is that IPPs be part of the auction process; hence the term "all sources bidding."

Our discussion of the efficiency and welfare benefits of the FERC NOPRs will be fairly general; many issues that relate to implementation details will be neglected. These implementation issues often raise major policy questions, such as the utility's role as a bidder in an all sources auction. For simplicity we limit the discussion to cases in which the utility functions only as a regulated producer. Following the FERC's approach, our discussion also generally ignores questions of transmission access. The assumption is that if an IPP purchase looks attractive, the buyer arranges for delivery of power. There are other possibilities for structuring competitive procedures in which the transmission system is more "open." These arrangements are logically part of broader questions involving competition and the evolution of the structure of the utility industry (see Kahn 1988a).

Any assessment of the implications of the FERC NOPRs is necessarily a comparison of the effect of these rule changes relative to some scenario of events absent the changes. However, it is important to note that there is widespread disagreement about the incentives for efficient investment in the electric utility industry in the absence of the FERC NOPRs. The principal reason for the diversity of views about the status of the regulatory environment is the unprecedented scope of disruption and change that has occurred during the 1980s. The economic losses from power plant cost over-runs and other events have placed great stress on the "regulatory compact" between the political authorities and the industry. Among the symptoms of these changes is the appearance of bankruptcy mergers. Such events suggest that the current economic environment is less stable and predictable than utilities have historically experienced. These events also imply that the future economic environment is uncertain. Understandably, therefore, there is no consensus on the future evolution of the industry and the role of regulation.

In this discussion we will outline three alternative views of the prospects for electric utility regulation. The impact of the FERC NOPRs looks different from each of these perspectives. We begin with capsule sketches of the three alternative characterizations of utility regulation in a "no

NOPR" world (section 2). We refer to these characterizations as "baselines." We discuss briefly the kind of evidence needed to support one of these views against the others as being the more "appropriate" characterization. In section 3, we characterize the changes in the utility environment brought about by PURPA implementation. We then draw upon the lessons gained from implementing PURPA to characterize the types of arrangements likely to emerge under the FERC NOPRs (section 4). In section 5 we apply this characterization to the three alternative views of the prospects for utility regulation in order to assess the welfare and efficiency benefits of the FERC NOPRs.

2. THE PROSPECTS FOR ELECTRIC UTILITY REGULATION

2.1 Three Baseline Scenarios

Baseline #1 - Capital Minimization

The dominant feature of the capital minimization scenario is a shell-shocked utility management that is so gun-shy of what it perceives to be confiscatory regulatory policy, that it will go to great lengths to avoid or defer capital investment in new generation. For example, the utility will satisfy its obligation to serve by relying heavily on either short- or long-term purchase agreements. Cost recovery for such purchases would not often be subject to the prudency reviews that reduce shareholder earnings, and, in any event, the sums at risk are smaller than for new plants. If the purchase power strategy could not satisfy requirements, then the utility would invest in combustion turbines as a last resort. The motivation for choosing combustion turbines is their minimal capital costs, thereby limiting the exposure of capital to regulatory confiscation. Given the inherent risks of the economic environment, the capital minimization strategy is optimal.

Baseline #2 - Rolling Prudency Reviews

In this scenario utility management and the regulatory commission share decision making authority and its risks in an unprecedented manner. Resource planning is done on a joint basis with the explicit understanding that prudency reviews will be periodic, but will not impact cost recovery. Thus if a capacity expansion decision is undertaken at one point in time, and later proves to be mistaken, the utility will abandon the project in question but will recover, within agreed upon parameters, all costs incurred up to that point. In this scenario, it becomes difficult to draw the line between management perogative and responsibility on the one hand, and the review and constraint function traditionally associated with regulation.

Baseline #3 - Optimal Risk Aversion

In this scenario management is risk-averse with regard to future investment choices, but not to the degree implied by Baseline #1. There is no merging of management and regulatory responsibility in this scenario in contrast to Baseline #2 . Government's role is strictly limited to policing monopoly power in the regulated firm; it does not attempt to balance competition with regulation. Management assumes its traditional planning function and bears the risks of its investment choices. Given the expectation that these choices will be subject to prudency reviews, management responds to the incentive to minimize cost, and makes the economically optimal decision.

2.2 Distinguishing Empirically Among the Alternative Baselines

Obviously the three scenarios just sketched cannot all be simultaneously true, at least in any one jurisdiction. It is possible that they may co-exist in different jurisdictions. Alternatively, over time it may become evident that one of these turns out to describe reality most closely. It is useful to ask briefly how we would know when any of these descriptions could be called more nearly accurate than another.

The weakest, but most abundant, class of evidence consists of assertions by various actors about what they take the status of utility regulation to be, or what it ought to be. The difficulty with evidence of this kind is that it may consist largely of self-serving strategic posturing by parties that are ultimately bargaining for undisclosed interests. Thus, when representatives of the electric utility industry argue that the capital minimization scenario (Baseline #1) describes reality, they may actually be using the threat of a capital strike to induce regulatory behavior resembling Baseline #2. It is interesting to note that many of the advocates of Baseline #1 represent utility management (e.g., the Chairman of San Diego Gas and Electric who is widely quoted on this point)[1]

More theoretical arguments which support the same proposition have been associated with the Electric Power Research Institute (Peck, 1983 and Chao, Gilbert and Peck, 1984). These arguments rely on the proposition that the cost of capital exceeds the allowed regulated return on equity. This disparity drives the capital minimization result. These theoretical arguments have a tautological quality in the sense that they suppress the crucial empirical question; namely whether the cost of capital is greater than the allowed return? Unfortunately, the only hope for answering such questions lies in statistical studies of stock market data where empirical correlates of substandard financial performance might be detected. One interesting study which is in this genre did find a significant relation for 1983 and 1984 data between the burden of utility construction programs and utility stocks selling below book value (Putnam, Hayes and Bartlett, 1986). This study found that incremental investment reduces shareholder returns. The problem with relying on such studies is that they describe the past rather than predict the future.

More persuasive kinds of evidence involve actions rather than statements. However, it is not always easy to separate the two, especially when commitments over long periods of time are involved. A useful example of this difficulty involves potential support for the plausibility of Baseline #2. The hallmark of this scenario is the close involvement of the state regulatory authorities in the planning process. This paradigm of shared responsibility has come to be

[1] See FERC, "Notice of Proposed Rulemaking, Regulations Governing Independent Power Producers," Docket No. RM88-4-000, March 16, 1988, note 28.

associated with the "Least Cost Utility Planning" (LCUP) movement. The degree to which this movement has taken root among the various state commissions has been documented by the Energy Conservation Coalition, an advocacy group which promotes LCUP (Shapiro, Markowitz and Hirsh, 1987). An explicit goal of this approach is the elimination of prudency reviews at least with respect to planning decisions (Hirst, 1988). Segments of the utility industry interested in renewed generation construction programs also support this approach (Dowd, 1987).

There are, however, very real questions about the ability of regulatory commissions to commit themselves, in fact, to a long-term policy. A fundamental problem involved with identifying Baseline #2 definitively lies in the inability of regulatory agencies to make credible long term commitments. The usual characterization of this is the unwillingness or impossibility of current administrators to bind future administrators to a particular course of action. In its extreme form, the regulator can even force utilities to break contracts they have signed with third parties. Thus not only is there a lack of long-term credibility, a matter involving the regulator's own actions. With regard to the utility, this lack of credibility can also adversely affect the utility's dealings with suppliers.

Even where aspects of the LCUP paradigm are embodied in state legislation mandating a shared planning process, there is very little in the way of state mandates to eliminate the potential for prudency reviews for planning decisions, or guaranteeing cost recovery for abandoned projects. Therefore, even where evidence exists that LCUP may frame the utility planning debate, this does not constitute commitment to shared responsibility. LCUP rhetoric may actually result in an outcome more like Baseline #3 than Baseline #2. As long as the regulator resists the temptation to become co-opted into the planning process and guarantee cost-recovery, LCUP may just be the kind of regulatory threat that induces optimal managerial risk-aversion. Indeed, LCUP rhetoric may also amount to signalling Baseline #1 by the de facto veto of central station generation investment.

The only actions that might constitute strong evidence for a given scenario are those which preclude other possibilities. For example, Virginia Power's recent large scale solicitation for power contracts appears to represent the utility's power supply strategy for its requirements over the foreseeable future. Because the evaluation criteria have not been identified in precise detail, it does not seem to fit the pattern of shared decision-making which characterizes Baseline #2. On this particular point the Virginia Power solicitation appears somewhat at variance from the FERC NOPR procedure, which requires explicit state approval in advance of the evaluation criteria. Virginia Power's approach looks more like our Baseline #1 than either of the other scenarios. The key distinctions are the lack of shared responsibility with regulators, and the utility's refusal to invest capital in new baseload capacity. By undertaking these actions the utility appears to have precluded other options.

A final note about Baseline #3 is appropriate. Evidence in support of this scenario may be difficult to identify. One particularly clear case would be a situation in which a utility constructed a coal-fired generator without the kind of pre-approval guarantees associated with Baseline #2. This would tend to show that Baseline #1 did not apply because the choice of technology was not capital minimizing. Lack of regulatory guarantees would also rule out Baseline #2. Other cases are substantially less clear. Suppose the utility announced its intention to construct an integrated gasifier and combined cycle plant (IGCC). This technology is modular in nature. A combustion turbine is constructed initially, while a steam generator is added at a later date to boost capacity and efficiency. Finally, a coal gasification unit is added at some point. This last step is the most expensive and capital intensive. It is also the least assured. There is no inherent need to take this step unless natural gas prices increase very substantially. Until this step is taken, however, the IGCC option is not really distinguishable from Baseline #1. Thus announcement of an IGCC option cannot really be taken to indicate anything. It may well be that this is the attractiveness of the IGCC option to utility management.

3. IMPACT OF PURPA IMPLEMENTATION

Since the motivation for the FERC NOPRs arises out of the responsibility to review the implementation of PURPA, it will be useful to summarize the history of private power under PURPA. The point which we wish to emphasize in this discussion is the important role that long-term contracts have played in the PURPA process. This aspect has not received as much emphasis in the FERC's hearings on this subject as, perhaps, it deserves.

The original FERC rules for implementing PURPA explicitly allowed for long-term contracts as a substitute for short-term revisable tariffs (see Section 292.304 (d)). The contract possibility was not required as a feature of state implementation. In retrospect, however, it can be said to have made all the difference. In those states which made long-term contracts available, there has been a very substantial supply response. This stands in marked contrast to the limited response that has occurred in states where only short-term tariffs were made available. A recent assessment of PURPA implementation by the New Jersey Board of Public Utilities made this point in reference to the Jersey Central Power and Light Company (JCP&L).

> "In the first four years after the Board propagated its avoided cost standards in Board Order 8010-687 on October 14,1981, and despite its capacity and energy supply deficiencies, JCP&L had no approved power sales agreements with qualifying facilities. Since the implementation of standard contracts, over 700 MW have signed contracts with Jersey Central, alleviating any capacity deficiency and erasing the construction of coal plants from their supply plan." *(An Assessment of Cogeneration and Small Power Production in New Jersey 1981-1986, 1987, pp. 8-9)*

Additional evidence on the role of long-term contracts is apparent from the enormous response to Interim Standard Offer No. 4 (ISO4) made available by California utilities from 1983 to 1985. In this case, it has been argued that the response was due to an over-estimate of price. Because the ISO4 price terms were too generous, suppliers rushed to sign contracts. However, more recent data on competitive processes, where bidding has the effect of tending to eliminate excess rent, also shows a substantial response of supply to long-term contract opportunities. For example, Boston Edison announced its intention to acquire 200 MW of new supply through competitive bidding for contracts. Responding bidders offered over 2000 MW (Whippen, 1988).

Similarly, Virginia Power received bids from QFs and IPPs totaling 14,000 MW in its auction for 1700 MW of power.

To prepare for our analysis of the FERC NOPRs, it will be useful to assess the impact of PURPA on the regulatory process. In particular, we will briefly characterize how our three baseline scenarios might be affected by the evolution of PURPA absent the FERC NOPRs. The first and most obvious effect of PURPA implementation has been a broadening of the options for utility purchases beyond the wholesale market which otherwise consists primarily of excess utility-owned supply. In the traditional wholesale market, transactions are typically of relatively short duration. Requirements sales to distribution companies that have minimal generation capacity of their own are the primary exception to this trend. These sales tend to occur as part of long-term contracts. In the other wholesale segment, sometimes known as the co-ordination market, there is typically a mix of essentially spot market sales and contracts of brief duration, (i.e., one or two years). Longer term wholesale contracts have come into play more recently as some utilities have shifted to a purchasing strategy.

As our previous discussion indicated, PURPA implementation has tended to imply long-term contracts. These contracts establish avoided energy and capacity payments for at least ten years. This characteristic is due mainly to the financing structure of PURPA projects (see Kahn and Goldman, 1987). Typically, these projects are more leveraged than the capital structure of most utilities. The debt associated with PURPA projects must be supported by power sales revenues alone; the projects are financed most often on a "stand-alone" basis. Therefore, lenders require a contractually specified price to provide security. The pricing need not be completely fixed, but it must be indexed to changes in cost or value in a way that promises a reasonable coverage of debt service.

Thus PURPA may be seen as part of a process in which utilities become committed to long-term supplies through contracts rather than ownership. This shift transfers performance or operating risk to the supplier. If the supplier does not produce, he is not paid. This creates an incentive to maximize production. Typically the PURPA contracts have only very limited provisions for dispatchability. The utility has an obligation to purchase, and cannot curtail unless there is an explicit contractual provision to that effect. In some situations this requirement can lead to uneconomic dispatch, because, under its PURPA obligation, the utility must purchase at times when it has lower cost resources available that it cannot use. Pacific Gas and Electric Company discusses this problem in its comments submitted during FERC's PURPA implementation hearings.

From the perspective of Baseline #1, PURPA was beneficial to utility management, if not necessarily to society. By broadening the range of resources available for purchase, PURPA allowed utility management to avoid investment and its perceived risks. The utility was not subject to prudency review, provided that it followed the lead of its regulators in offering contract terms. This has not been uniformly the case.

A prominent counter-example is the non-standard contracts that Southern California Edison signed with its subsidiary, Mission Energy. These contracts involve in excess of 1000 MW of cogeneration capacity in which SCE's subsidiary owns a substantial minority share. By 1989, production from these projects will exceed 10% of SCE's energy mix. The California Public Utilities Commission has launched a prudency review of the Mission Energy contracts because of the magnitude of these arrangements and their deviation from the terms of California's "standard offers." This investigation is expected to be lengthy.

Regardless of the outcome in the SCE/Mission Energy case, its occurrence has important implications for Baseline #2. In essence, this example illustrates the difficulty of removing retrospective re-examination from the regulatory process. The emergence of Mission Energy as a major component of the Southern California PURPA market occurred gradually, and in the context of an environment that was supportive of new ways to encourage cogeneration development. It was not anticipated that these contracts would become the subject of prudency review. However, in some sense, Baseline #2 implicitly assumes that all relevant decisions and their implications can be known in advance. The rolling prudency review is then a self-correcting, "no fault," approach to planning that accounts for imperfect estimation of known problems. The difficult assumption here is that all problems are known and formulated in a manner sufficiently explicit to be dealt with in advance. The only uncertainty is parameter estimation, not problem identification. Structural changes such as PURPA create situations that cannot be anticipated in advance. This environmental instability threatens the viability of a scenario like Baseline #2.

A final comment on Baseline #3 is appropriate. While PURPA has created opportunities to reduce or transfer the risks of utility investment, it has not eliminated them. As the previous discussion indicates, PURPA has also created new uncertainties. It is hard to say definitively whether the added flexibility under PURPA outweighs the increased uncertainty. To the degree that utility management controls the potential excesses under PURPA, such as too many contracts, the potential for a positive outcome under Baseline #3 is increased.

4. IMPACT OF THE FERC NOPRs

In this section, the potential impact of independent power producers in the electric generation market is discussed based on the terms and conditions outlined in the recent FERC NOPRs. There are very substantial uncertainties about what kinds of suppliers would emerge in the event that the FERC NOPRs were implemented as formulated. We examine the prospects for different technology types and operating profiles.

4.1 Factors Affecting Technology Choices of IPPs

One view is that the class of IPPs would consist largely of gas-fired combustion turbines. This position is articulated clearly by Rochester Gas and Electric and New York State Electric and Gas (1987). These utilities argue that IPPs will maximize profits by adopting a capital minimizing strategy. They will have higher financing costs than regulated utilities because they are less well capitalized and must use higher depreciation allowances. These extra costs will drive IPPs to minimize capital investment by adopting gas-fired combustion turbines.

Several analysts have argued that coal-fired technologies will emerge as a dominant class of IPPs. Proponents of this view argue that coal has particularly innovative technology possibilities. New developments in coal combustion technology promise lower cost ways of generating electricity while meeting environmental standards (Balzhiser and Yeager,1987). These "clean coal" technologies are still in the demonstration or early commercialization stages of development and have not reached the maturity of oil- and gas-fired generation. Therefore, they pose investment risks which might deter utility planners. IPPs, who would have profit potential beyond cost-of-service rates of return, might be more willing to invest in these technologies.

If this is the case, it might be asked why these technologies have not emerged under PURPA. The largest share of new capacity built under PURPA has been oil- and gas-fired cogeneration. Given the PURPA restrictions and the relative values of process steam and electricity, it often turns out that a cogeneration application will generate greater profits using combustion turbines than coal-fired steam turbines. Combustion turbines have a much higher ratio of electricity production to useful heat than steam turbines (Joskow and Jones, 1983). Since the value of electricity is greater than the value of steam, QF developers have had a tendency to choose oil- and gas-fired combustion turbines. Other factors favoring gas have been low fuel costs and the need for scale economies in coal applications. If PURPA projects are small, then scale economies can not be captured.

It may well be that the competition between fuel types hinges on regulatory factors. A particularly important variable is the length of contracts that are subject to all-sources bidding. For example, because of relative differences in capital intensity and the requirement to amortize over appropriate periods, long-term contracts that can be signed for 20 years or more favor coal projects, while contracts that are limited to 10 years favor gas-fired cogeneration projects.

Coal projects often require longer contracts because of fuel supply issues. For example, contracts for coal used in utility power plants are commonly for 20 years or more (Joskow, 1985). A primary reason for this is that mining investments are often required on a dedicated basis. Thus long-term contracts are desirable from the perspective of the coal seller. The IPP buyer of coal will also have an incentive for long-term contracts. The coal-fired IPP needs a long period of time to amortize his capital investment. His bid is therefore of a long-term nature. To stabilize expected return it is desirable to "lock in" fuel costs. The cost of coal is generally indexed in long-term utility contracts based on formulas of varying complexity. Typically, these formulas are indexed to components of the producer's cost, not to market value.

Incentives for contracting in gas appear to differ. The gas producers typically are not required to make dedicated investments for a particular sale. Gas price fluctuations give producers less incentive to specify sale prices for long time periods. While long-term contracts are attractive to suppliers as a means of guaranteeing markets, there has been relatively little contracting of this type recently. Where such contracts occur, the price formula allows for flexibility based on changing market conditions (Mulherin, 1986 and Bayless, 1988). This is quite different than the price adjustment mechanism for coal contracts which is based on supplier's costs.

On the gas purchaser's side, the need for price assurance is determined most strongly by the financing arrangements of developers. Gas-fired cogeneration projects are often financed by ten-year debt (Kahn and Goldman, 1987). It is not uncommon for gas-fired cogenerators to obtain five-year fixed price fuel contracts that offer the possibility of ten years of additional supply at a subsequently negotiated price. Price specification beyond five years may be achieved by indexing to a gas utility's publicly known weighted average cost of gas. Consequently, gas-fired cogenerators need power purchase prices that are indexed to gas costs.

Therefore, the specification of contract lengths has a major impact on the fuel choices of suppliers. California's ISO4 specified ten-year contracts for energy payments, and the supply response was overwhelmingly natural gas. In contrast, Virginia Power is offering 25-year contracts and has clearly stated a strong preference for coal. It would appear that these choices will depend on local considerations, not the least of which is the regional fuel supply mix.

4.2 Operational Characteristics of IPPs: The Issue of Dispatchability

Operating profiles are also at the discretion of purchasers. In this regard the FERC NOPRs are likely to encourage more diversity than PURPA, because there will be no obligation to purchase from IPPs as opposed to QFs. The PURPA obligation to purchase tends to make QFs essentially baseload producers rather than load-following or dispatchable producers. This does not always meet utility needs. The Virginia Power solicitation, which in some ways anticipates the FERC NOPRs, places substantial emphasis on dispatchability. However, the Request for Proposals does not explain how dispatchability will be evaluated. For bidders who do not wish to offer dispatchability, the RFP does indicate a maximum price to be paid for "must take" power. This price is designed to be unattractive.

Dispatchability is important for utilities, although it is difficult to develop a comprehensive definition and to value it in advance. Therefore, it will be difficult to design a formal auction procedure that selects producers offering different degrees or definitions of dispatchability. One standard approach for dealing with such situations is to reserve for subsequent negotiations details of this kind. The NOPRs are somewhat ambiguous on the relative role of formalized bidding and negotiations. The principal discussion on this point comes in the bidding NOPR (sec. III. D. 3). This section discusses the specific issue of protecting the fairness of the bid evaluation process by restricting the utility from simultaneously negotiating with non-bidding suppliers. However, the situation involving different degrees or kinds of dispatchability will be more complex.

A hypothetical example in which all bidders offer the same capacity (e.g., 100 MW), but varying levels of operational control illustrates the practical difficulties of valuing dispatchability. Suppose Bidder A offers 100% curtailment 10 times per year for periods of one week. Bidder B offers 50% curtailment for up to 4000 hours per year. In energy terms the two bids are similar, 168 GWh from Bidder A and 200 GWh from Bidder B. However, these two bids might be very different with respect to their capacity value to the utility. Due to operating constraints, utilities often run units at times, particularly weeknights, when they do not appear economic in an instantaneous sense. But since the unit will be needed later to serve weekday loads, and it cannot be stopped and restarted quickly, it must be run continuously. The value of turning off Bidder A at these times may be more than twice the value of curtailing B. The process of deciding how to schedule under these conditions is called the unit commitment problem in the engineering literature. Representing this process in production simulation models is complex (Kahn, 1988b).

Next suppose we have Bidders C and D that offer the same terms as A and B respectively, but at prices that are 10% higher than their counterparts. The utility must decide what the price/dispatchability trade-off is for all combinations. If Bidder A is worth more than Bidder B, is Bidder C worth more than Bidder B also? Typically, the utility will use a production simulation model to make this decision, although these models are imperfect representations of the process. If Bidder C will reduce his price slightly, he may be preferable to Bidder B. If he will not, then perhaps the utility accepts the bids of A and B. At some later time the utility negotiates with Bidder B for a greater percentage curtailment at a higher price. This may then make his contract look more like Bidder C who has been rejected.

If subsequent negotiations are forbidden in the interest of ex ante fairness, we may lose ex post efficiency. Clearly there is a conflict between the goal of explicit auction acceptance rules, and adaptability to changing circumstances. This is essentially the same issue that FERC discusses in the Avoided Cost NOPR in the more general context of fixed price contracts. In this case, FERC's position on subsequent adjustments is considerably more flexible. The discussion titled "Reopeners and Trueups" does not rule out procedures for changing the terms of contracts when they have gotten out of line. The main difference in that context is simply timing. Adjustments are allowed *after* it is obvious that mistakes were made, rather than in anticipation of them.

It is also useful to distinguish negotiations conducted during the bid selection process from those conducted after projects are selected. FERC's concerns about ex ante fairness apply in the former situations. If buyers negotiate with non-bidding suppliers during the selection process, then the process could be biased against bidders that competed formally. The danger of sweetheart deals with favored suppliers is one major concern. Alternatively, informal offers of doubtful validity might be used by buyers to bargain down the offers from formal bidders. Thus, on balance there is good reason to limit negotiation during the selection process.

The problem with subsequent negotiations involves the credibility of commitments. Even if both parties could gain from an ex post re-negotiation, there is no mechanism to force one. If sellers believed that they could benefit from subsequent negotiation, then they may assume that their initial contractual commitments are not actually binding. Thus, allowing for too much flexibility may end up producing too little commitment, or perhaps inefficient commitment (Hart and Holmström, 1987). Therefore it would be advisable to limit the potential scope of negotiation to those issues where it could make a substantial difference such as dispatchability.

It is unlikely that the value of dispatchability can be adequately predicted at the outset of a bid solicitation. The structure of contracts dealing with this issue will be complex. It is reasonable to assume that there will be a role for subsequent negotiation in this area under any regulatory regime.

While the FERC NOPRs can be expected to broaden the range of contractual possibilities, they will have intangible costs in the area of coordination and cooperation among utilities. As more competitive forces are allowed in the electricity market, there will be less of the informal sharing of information and exchange of services that has characterized relations among electric utilities until rather recently. PURPA introduced some competition between utilities as QF subsidiaries of one utility entered the service territory of another utility. Expanding the possibilities for entry through the IPP mechanism will exacerbate the potential for conflict of interest among utilities. To the degree that utilities increasingly compete in one another's service territories, the tendency toward cooperation will diminish. Potential problems include lack of emergency support, failure to provide transmission services, and the loss of opportunities for joint ventures.

5. WELFARE AND EFFICIENCY BENEFITS OF ALL SOURCE BIDDING

In this section we will evaluate the impact of the FERC NOPRs as characterized in Section 4 under the three alternative views of the prospects for electric utility regulation (section 2). We assume that the FERC NOPRs on bidding and reduced regulation of independent power producers are both implemented. Because the three baselines differ so dramatically, we analyze the outcome from each reference point separately.

5.1 Baseline #1 - Capital Minimization

This scenario is quite close to the industry characterization that appears to underly the analysis contained in the NOPRs.[2] In a world where investment incentives are inadequate, it is desirable to identify parties that are willing to bear supplier's risks. The auction process should help to identify such parties. It is likely that they will be found among the traditional vendors of supply services to the regulated utilities; architect-engineering firms, equipment vendors, constructors, fuel suppliers and investment firms. The IPP NOPR explicitly acknowledges this as the probable outcome (p.59).

Under a capital minimization strategy by utility management, incremental supply will depend on complex contracts with QFs and IPPs. There is a substantial range of policies that might guide the nature and types of contractual relations between utilities and independent producers. As indicated in Section 4 the choice of contract terms will influence the fuel choices of suppliers. The degree to which purchasers bear the demand forecasting, fuel costs, and other risks will influence the magnitude of the supply response. The more risk that is shifted to suppliers, the smaller will be their willingness to invest. Therefore, the utility must decide the

[2] See for example the Discussion section of the IPP NOPR, Section A: Need for a New Rule, Part 1: Problems in the Industry.

degree to which it will accept "take or pay" clauses, or pricing terms that otherwise immunize private investors from fluctuations in market value.

The benefits of the FERC NOPRs under Baseline #1 are likely to be considerable. This occurs as much because of the unsatisfactory state of affairs absent the NOPRs as because of the unmitigated benefits of bidding and IPPs. Added competition from IPPs will have the effect of reducing economic rents to QFs. Whatever contractual inflexibilities are associated with IPPs, they are not likely to be worse than those associated with QFs. In all likelihood, because there is no obligation to purchase from IPPs, the contractual terms ought to be more favorable to the purchaser.

It is likely that dispatchability will be a continuing problem in this scenario. Because the contracting process cannot be expected initially to work efficiently for the intermediate load segment, we should expect continual negotiation and experimentation in this area. The outcome will be less efficient in this scenario than in others because the utility is not a credible alternative to provide incremental dispatchability. Combustion turbines, the only utility option, are not a true load-following resource; their efficiency at part load operation is typically quite poor. They can only be expected to operate a small number of hours per year (i.e., several hundred hours). In fact, the increase in the number of hours of turbine operation is one measure of the inefficiency of contracting for dispatchability. In extreme cases this might rise to several thousand hours.

The competitive pressure created by IPPs should not be confused with full-scale free market competition. The trade that occurred would be highly structured and constrained. There will not be a true spot market in electricity under the FERC NOPRs in any of our three baseline scenarios. There are a number of barriers to such a market. They include transmission access and pricing questions, which are complex and controversial. Other barriers to free entry also exist. The FERC NOPRs induce competition for the right to contract. For this to be a welfare improvement, it is only necessary that contracts be more efficient than other alternatives. In the capital minimization scenario, the only other alternative on the supply side is combustion turbines. As long as IPP prices stay below combustion turbine power costs, all sources bidding will be a welfare improvement. Even so the contracting environment will involve many rigidities, which leaves opportunities for increased efficiency.

In this scenario, as in all others, some account must be made of transaction cost increases. Since Baseline #1 already involves a primary reliance on purchases for incremental supply, the added transaction costs from the presence of IPPs will only involve evaluation of different supplier characteristics compared to the population of QFs. As indicated in Section 4, this might involve different fuel types. If IPPs add more coal-based resources to the bidder population, then the purchasing utility must develop a method to compare and evaluate bids with different characteristics. Such an analysis can become complex and subtle, especially when risk and uncertainty issues are factored in explicitly. An example of one approach to this problem is given in Chernick (1987) where the comparison is made for QFs. In the IPP context this problem can be expected to loom larger.

Apart from transactions costs on the front end of the purchase, there can be expected to be on-going costs of contract compliance, and costs associated with project failure. IPPs will probably impose fewer of these costs due to exogenous market effects, but more due to technical risks than in a purely QF purchase market. If we assume that IPPs imply a reduced reliance on gas, then the potentially harmful effects of a gas market tightening are reduced. On the other hand, IPPs adopting new technology may experience operating problems and perhaps project failure. In these cases liens or other security interest in the project are not likely to be worth much.

On balance the expected benefits in Baseline #1 would probably exceed the increased transaction costs. The only circumstance in which this might not occur would be the accumulated failure of new technologies. Under these circumstance there would be only added transaction costs and not much in the way of long run competitive benefit. While such outcomes are logically possible, the probability of large numbers of unrelated technological failure is small.

5.2 Baseline #2 - Rolling Prudency Reviews

This scenario is based on a concept of regulatory reform that emphasizes shared responsibility between utility management and the political authorities. The burden of decision making will be shared, and planning will be conducted on a "no fault" basis. What this would mean in practice is that regulators would periodically review previously approved plans, determine whether they should proceed, and provide for cost recovery of expenses within previously agreed upon parameters. This iterative process has been called "rolling prudence" (Dowd, 1987). The major issues to be addressed in this framework would be the mix of supply-side and demand-side opportunities to be pursued, and within the supply-side alternatives the role of private producers versus utility construction. The paradigm of shared responsibility is advocated both by proponents of increased emphasis on demand-side management (DSM) and by advocates of increased supply-side construction by utilities (e.g., the group of companies represented by Dowd). For the purposes of this discussion we will assume that the questions involving the proper role of DSM have been resolved, and that a residual need for additional supply has been determined.

IPPs can be expected to have less bargaining power in this scenario than in Baseline #1. Because the utility's own construction program is a credible alternative to QF, IPP, or purchases from other suppliers, there will be less need to provide favorable contract terms. This may not eliminate "take or pay" clauses, but it should reduce their role. In some ways there is an equivalence between the guarantees for cost recovery provided by the "rolling prudence" approach and the "take or pay" contract clause. Both are risk transfers from producers to consumers. An underlying premise of Baseline #2 is that such transfers are necessary and perhaps even socially desirable compared to an alternative of insufficient or excessively costly supply. Under the assumption that these risk transfers are necessary, Baseline #2 at least provides a competition of sorts between the regulated and unregulated mode of implementing them.

One would expect less IPP development in Baseline #2 compared to Baseline #1. This would be due to competition with regulated utility generation primarily, rather than competition only with QFs. There is nothing about Baseline #2 that distinguishes it from Baseline #1 with regard to QF's. To understand the role of IPPs in Baseline #2, therefore, it is useful to examine the relative advantages of regulated versus unregulated generation. As might be expected there is no general agreement about the comparative advantages. A qualitative discussion of factors contributing to one side or the other is useful for analysis of both Baseline #2 and #3 where both kinds of production might occur. Regulated construction has been ruled out of Baseline #1 by definition, except for combustion turbines.

Unregulated power producers typically have a more leveraged capital structure than regulated utilities. The relatively lower cost of debt compared to equity capital means that financing costs should be lower for the unregulated producer. The downside of this financing advantage is that the more leveraged firm is more vulnerable to bankruptcy during times of economic distress.

Regulated generation is likely to have an advantage in site acquisition. Utilities can exercise the right of eminent domain to acquire sites for plant construction. This power is not available to unregulated firms. Economic benefits associated with favorable sites include lower fuel transport and storage costs, better access to transmission, and more favorable location in the power network. This last factor can have a number of benefits to total system operation such as improved power flows (making cheaper purchases possible) and lower costs for voltage support. Although factors such as these may be difficult to quantify in a bid evaluation system, they are no less real.

It can be argued that neither the financing cost advantage of IPPs nor the site acquisition advantage of regulated generation represent true social cost economies. They both could in principle be made available to any party. More fundamental social efficiencies lie in the areas of construction practices, technology innovation and system integration. The incentive for efficient construction practices is stronger for QFs and IPPs than for regulated firms. This is due to the cost-plus nature of regulation, where only imprudence can be easily identified and punished, but excellence is hard to identify and reward. Technology innovation is also likely to favor IPPs, at least initially. The key difference again is the ability to capture gains. The main difference between technological innovation and construction practices is the discrete quality of the former. New technologies are risky when first introduced, but as experience is gained perceived uncertainties diminish. Thus IPPs might be more willing to take the first steps with an innovative technology, but regulated suppliers might well follow up if demonstrations are successful.

On balance the FERC NOPRs are likely to be beneficial under Baseline #2. Their relative impact in this scenario will be arguably smaller than in Baseline #1 for two reasons. First, less IPP development will occur in this case, because regulated production will still play a role. Second, the baseline scenario without the FERC NOPRs is a less costly one than in the capital minimization scenario. Therefore the gains of associated with any level of IPP development will be smaller. However, since IPPs will compete directly with utility projects there should be efficiency gains absent in Baseline #1 where such competition is absent.

Some of the costs associated with IPPs in Baseline #2 will be greater than in Baseline #1 and some will be smaller. Due to the competition with regulated production, IPP contract terms can be expected to be somewhat less onerous for consumers. The need for concessionary terms will be reduced. It is unlikely that these terms will disappear, however. In a relative sense the inflexibilities associated with IPP contracts may be greater in Baseline #2 than in Baseline #1. This is because there will not be an opportunity for mid-course correction, i.e. "rolling prudence," with respect to IPP contracts. Thus if the shared planning process results in an overestimate of supply requirements, only the utility project will be cancellable, and not the IPP contract. If the IPP contracts were abrogated, there would be negative effects on long-run supply due to the loss of contractual credibility. The burden of inflexibility will be borne by the consumer to a substantial extent.

There should be less of a problem with dispatchability in this scenario than in Baseline #1. Under this scenario, utilities will compete with private producers to serve intermediate load; the utility's negotiating position is improved because there will be a reduced need to rely exclusively on contracts. The issue of subsequent negotiations, however, will probably be less favorable than in Baseline #1. Because the regulator is so closely tied to all decisions in Baseline #2, there will be less leverage on private producers after contracts have been signed. The ability of the regulator to threaten abrogation of an ex post unfavorable arrangement is reduced if the regulator has signed off explicitly on the arrangement in advance.

The balance of costs and benefits of the FERC NOPRs is more narrow in Baseline #2 than in Baseline #1. The trade-off boils down to weighing the advantages of potential innovation and competition from new players against the inflexibilities of IPP contracts. The shared responsibility regulatory paradigm has the virtue of keeping the presence of a regulated supply capability at the cost of shifting adjustment costs to the consumer.

5.3 Baseline #3 - Optimal Risk Aversion

The fundamental assumption of this scenario is that the regulatory upheavals of the 1970s and 1980s have made no really permanent change in the industry environment. Exogenous shocks and management errors of the past may have induced a more appropriate risk aversion, but neither the retreat from investment, nor the shared responsibility characteristic of the other scenarios is a real long run equilibrium. Utilities retain monopoly power and will invest in new capacity when appropriate. The function of regulation is to restrain that market power, and not cross the line into centralized government planning. The limited ability of government regulation to optimize economic welfare is an implicit assumption in Baseline #3. Ambitious regulatory interventions to direct planning or to "manage" competition are doomed to failure and will result in counter-productive effects.

From this perspective, the PURPA experience is not an unmitigated success. The cases of substantial QF development in response to long-term contract opportunities are signs of excessive and inappropriate regulatory intervention that created artificial economic rents for private developers at the expense of consumers. In most cases these contracts were urged on utilities by the regulatory commissions without due regard to appropriate price and/or quantity restrictions. The reform of PURPA as a bidding system, therefore, is a potentially positive development. This reform should reduce the burden of an excessive number of over-priced long term commitments.

The more chronic problem of PURPA in this perspective is the creation of a politically potent constituency interest that can exercise market power. This constituency has its political entitlement embedded in the obligation to purchase placed on the utility. To the degree that regulators have interpreted this to imply long term contracts, they have granted substantial economic and political power to the "QF industry." The creation of this industry can be interpreted, in part, as an abdication of regulatory oversight. Alternatively, it can be construed as an inevitably inept attempt to manage competition through government intervention.

From this perspective, the FERC NOPRs are another step toward the creation of a special economic interest of favored producers. The key problem with the IPPs is not only their ownership status but the implicit understanding that these transactions will be governed by concessionary contracts. Perhaps these will be less burdensome than PURPA contracts. While there is no obligation to purchase conferred with IPP status, the FERC NOPRs do assume that "take or pay" clauses will be a feature of the process. Even advocates of regulatory reform of the kind associated with Baseline #2 perceive the risk of favoritism for IPPs (see Dowd, 1987 and Rochester Gas and Electric and New York State Electric and Gas, 1987).

What then becomes of the benefits from additional competition? These depend substantially on the reactions of the regulated firm to the real or potential entry of IPPs. One outcome might be a retreat of management into a more risk averse posture than without the IPPs. This could be an evolution toward a situation similar to that in Baseline #1. Only in this case the harmful effects are caused by IPPs and not cured by them. A more aggressive utility management response might be to respond to the potential competitive advantages IPPs possess in a preemptive fashion. In this case management perceives that the biggest risk lies in not adopting innovative technologies or construction management practices.

In any case, the NOPRs force regulators to cope increasingly with competing suppliers. This is a difficult social task. Regulatory review of build vs. buy decision will occur after the utility has made it, rather than in an anticipatory, consensus-forming, shared responsibility framework. This will at least provide some negotiating strength to deal with inevitable errors in pricing and contracting. Unlike Baseline #2, the commissions will be more able to reject arrangements which, ex post, turn out to be uneconomic. This will have beneficial effects in areas such as dispatchability.

6. CONCLUSION

The FERC NOPRs represent a significant change from the PURPA world by enlarging the domain of private power production. The task of regulation will become more difficult in this process as the complexities of contracting are added to the problems of resource planning. Whether this change represents an overall improvement in welfare and efficiency depends upon one's view of the prospects for regulation in the absence of these initiatives. Our three scenarios contrast quite sharply in this regard. The benefits of all sources bidding are generally greatest where the failures of regulation are large. In this and all other cases, competition will reduce production costs. The differences arise over the issues of contractual complexity, rent-seeking and the prospects for a return to the traditional regulatory equilibrium. There is little doubt that transactions costs will increase under all sources bidding and that some inefficiencies will result. It is less clear whether these costs will be large; whether the system will degenerate into one with high-cost favored producers.

It is doubtful whether the precise system envisioned by the FERC NOPRs will come into existence nationally by federal action. The forces represented by this initiative, however, are strong and will develop in a number of jurisdictions. Other efforts for regulatory reform will also proceed. In some sense the three baselines delineated in this study represent different paths for the evolution of electric utility regulation. A period of regional experimentation would be valuable before definitive national action occurs; public policy should continue to encourage individual states to experiment and develop competitive procurement mechanisms.

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LAWRENCE BERKELEY LABORATORY
TECHNICAL INFORMATION DEPARTMENT
1 CYCLOTRON ROAD
BERKELEY, CALIFORNIA 94720