PURCHASED POWER RISKS AND THE LEVEL PLAYING FIELD

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EXECUTIVE SUMMARY

When a utility purchases power from an independent power producer (IPP) it typically enters into a long term take-and-pay contract where the utility makes capacity payments for power whenever it is available from the IPP. It is often claimed that such contracts virtually guarantee IPPs a stable revenue stream and hence allow IPPs to finance new capacity with greater reliance on financial leverage than a utility could employ to finance its own capacity expansion. Furthermore, a purchased power contract is a fixed liability of a utility and hence may increase the risk and reduce the debt capacity of a utility.

Section 712 of the National Energy Act requires states to consider the financial effects of purchased power. Specifically, states that require utilities to consider the long term purchase of wholesale power are required to examine the following issues:

(1) the effect of long term wholesale purchases (as opposed to construction of new generating capacity by utilities) on the cost of capital for utilities and the rates paid by consumers, and

(2) the extent to which the use of high amounts of financial leverage by IPPs gives them an unfair advantage or threatens the reliability of service.

This paper systematically examines these issues. In particular, we recognize that building new generating capacity involves real risks. The decision to purchase power, the terms under which the power is purchased, and the regulatory treatment of purchased power contracts determine (1) to what extent the various parties bear risk (the IPP, the utility, the ratepayers), (2) whether the parties are fairly compensated for bearing risk, and (3) whether power services are delivered to consumers in the most efficient manner.

Our analysis yields four major points:

(1) There is a "hidden cost" of purchased power to a utility if regulators fail to protect or compensate utilities for any "demand risk" borne by utilities that purchase power. This hidden cost attributable to demand risk will give IPPs a competitive advantage over utilities with respect to financing costs.

(2) While commonly cited, differences in the utility's and IPP's cost of capital are a poor measure of "hidden cost".

(3) Many of the potential advantages of IPPs are eliminated when public utilities create unregulated and separately capitalized subsidiaries that bid in competition with IPPs for new capacity.

(4) The highly leveraged nature of IPPs does not make them a less reliable power source.

Introduction.

Non-utility power producers evolved in response to the passage of the 1978 Public Utility Regulatory Policies Act (PURPA). PURPA encouraged the use of renewable energy resources and the more efficient use of non-renewable energy resources. Specifically, PURPA exempted qualifying facilities (QFs), cogenerators and small power producers, from utility regulation. PURPA further required regulated utilities to purchase the power produced by QFs at the utility's avoided cost. In subsequent years, non-utility power producers that do not meet the operating and efficiency standards of PURPA have also entered the power generation business. These independent power producers (IPPs) have no legislative right to sell power to regulated utilities. They must compete for the right to sell power. To encourage such competition, many state regulatory commissions have mandated competitive bidding for new power generating sources. In the 1980s, nearly 80% of the new generating capacity built came from IPPs.[1]

When a utility purchases power from an IPP, it typically enters into a long term take-and-pay contract where the utility commits to make capacity payments whenever power is available from the IPP. It is often claimed that these arrangements allow the IPP to enjoy a stable revenue stream and hence finance the capacity with large amounts of debt. Indeed, IPPs are typically financed with over 80% debt while public utilities are typically only half debt financed. Furthermore, the fixed supply contract enjoyed by the IPP is a fixed liability of the utility and hence may increase the risk of the utility.

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[1] These figures are quoted in Naill and Sharpe (1991) and were obtained from the Utility Data Institute, Directory of Selected U.S. Cogeneration, Small Power and Independent Power Plants April, 1990.

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Considerable debate has emerged regarding the effect of purchased power on public utility risk. For example, some authors claim that a utility will have less risk exposure if it enters into purchased power contracts as opposed to building new generating capacity.[2] Others argue that (1) purchased power increases the utility's risk exposure and (2) this increased risk is a "hidden cost" or a "financial externality" of purchased power.[3]

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[2] Roger F. Naill and Barry Sharp argue that purchased power lowers utility risk, "Risky Business? The Case for Independents," The Electricity Journal, April 1991.

[3] Lewis J. Perl and Mark D. Luftig argue that purchased power increases utility risk in "Financial Implications to Utilities of Third Party Power Purchases" The Electricity Journal, November 1990, and "Proper Risk Allocation in Build-vs.-Buy Decisions: A Response," The Electricity Journal, June 1991.

We conclude that both arguments have merit. These arguments, however, obscure what should be the key issue to regulators: does regulation of utilities and purchased power contracts insure that the low cost producers of electricity provide generation services in the most economically efficient manner <u>and</u> that the various parties involved are compensated for any real risks they bear. This, of course, is largely determined by regulatory policies.

Before presenting the details of our analysis, we provide a brief summary of our key points.

(1) The decision to acquire extra power capacity creates real economic risks for an electric utility. The utility can avoid a portion of these risks -- construction and operating risk -- by entering into a long term take-and-pay purchase contract with an IPP rather than building its own generation facilities. If these risks are large, the utility's existing securities may be safer if the utility purchases rather than builds new power capacity.

(2) Whether an electric utility builds its own power or enters into a take-and-pay purchase contract, it faces the risk that there will be inadequate demand for the new capacity. If the firm purchases power, the demand risk is spread only over its old assets. If it builds power, the risk is spread over its old <u>and</u> new assets. Thus, if we only consider demand risk, the risk per dollar of assets is higher when a utility purchases rather than builds. If we also take into account construction risk, it is no longer clear if the risks per dollar of assets (or the percentage of firm assets that can be safely financed with debt) is higher or lower when the decision is to purchase rather than build new power.

(3) Absorbing demand risk through a take-and-pay purchase contract is the so-called "hidden cost" to utilities of purchasing power. If utility customers must pay for capacity costs

associated with excess power, then there will be no hidden cost of purchased power. If, however, regulators (1) force the utility to bear demand risk and (2) do not compensate utilities for the additional demand risk associated with purchased power, then there is a hidden cost of purchased power. The fear that utilities may not be fairly compensated for bearing demand risk may be why utilities would rather not rely largely on purchased power. If purchased power contracts become a large fraction of power supplies, larger demand risks must be spread over a shrinking rate base, and attracting capital would require rates of return on capital that are politically hard to defend.

(4) If, in fact, utilities must bear demand risk, the risk associated with building new capacity is smaller for the IPP than is the risk for the utility. So, the IPP has a competitive advantage in financing its project -- a lower cost of capital. This competitive advantage cannot, however, be accurately measured by comparing the utility's and IPP's average cost of capital. The average cost of capital measures the risk of the firm's (utility or IPP) existing activities which is unlikely to be similar to the risk of any new project to expand capacity.

(5) It is desirable to have competition for the right to build new capacity. To keep the competition fair, we suggest four methods to level the playing field between IPPs and utilities by taking account of demand risk: (1) regulators can try to estimate the hidden cost of purchased power and adjust competitive bids between IPPs and utilities to reflect this cost, (2) consumers can be forced to bear demand risk, (3) IPPs can be forced to bear demand risk, or (4) utilities can form unregulated and separately capitalized subsidiaries that bid on new contracts against IPPs. The pros and cons of these approaches are discussed. We conclude that the fourth option

is best not only because it eliminates financing advantages, but because it provides for uniformity in regulatory treatment among competitors.

(6) The leverage associated with purchased power contracts is not likely to affect the reliability or the efficient delivery of electricity services. Shareholders and creditors of IPPs have the proper incentives to ensure reasonable reliability and efficiency of service.

We use the key points developed in our analysis to address the recent recommendations of the Florida Public Service Commission Staff regarding purchased power.[4] The staff recommendations stipulate that a utility contemplating purchased power must provide "a discussion of the potential for increases or decreases in the purchasing utility's cost of capital, the effect of the seller's financing agreements on the purchasing utility's system reliability, and any competitive advantage to the seller resulting from the seller's financing arrangements." First, our analysis indicates that a utility's cost of capital may go up or down due to the decision to purchase power rather than build capacity. This, however, is not the central issue to regulators. What is important is that IPPs may have an unfair competitive advantage in terms of capital costs due to the fact that utilities bear demand risk while IPPs do not. Given that Florida's regulatory policies seem to shelter utilities against demand risk to a large extent, we argue that any competitive advantage to IPPs is likely to be small. This advantage can be totally eliminated if utilities are allowed to compete through unregulated and separately capitalized subsidiaries. Finally, we argue that the seller's financing agreements should have no effect on the utility's reliability.

[4] The most recent recommendation of the Florida Public Service Commission Staff with regard to purchased power is provide in Docket No. 921288-EI dated May 6, 1993.

The remainder of this paper is organized as follows. Section I analyzes the impact of construction risk and demand risk in turn. Given the framework developed in Section I, Section II discusses the "hidden costs" of purchased power. Section III discusses alternative ways to level the playing field for competition between IPPs and investor owned utilities. Section IV uses the basic principals laid out in Sections I and II to evaluate the proposals for the evaluation of purchased power contracts put forth by the Florida Public Service Commission Staff.

I. Two Sources of Risk in Adding Capacity: Construction Risk and Demand Risk.

This section provides a systematic analysis of the risks of building a power plant. For simplicity, risks are categorized as "construction risk" and "demand risk".[5] The analysis examines the effects of these risks on utility investors, IPP investors and ratepayers in the case where the utility builds the new capacity and the case where the IPP builds the new capacity.

The analysis assumes the following stylized structure. First, if power is purchased, the utility and IPP enter into a take-and-pay contract where the utility purchases the power supplied by the IPP at an agreed upon rate if the power is available. This is the standard contractual form used in most purchased power contracts. Second, consistent with current regulations, the utility is allowed to pass through its cost of purchased power to the ratepayers on a dollar-for-dollar basis. Third, new construction cost overruns are not allowed into the rate base. Fourth, excess capacity is disallowed from a utility's rate base on the grounds that it is not used and useful. Fifth, regulators do not acknowledge any increase in risk caused by purchased power contracts

[5] This risk dichotomy is widely used by various authors as well as evaluations of the risks of purchased power published by bond rating agencies.

when calculating an allowable rate of return for investor-owned utilities. Sixth, IPPs operate in a competitive market. It should be noted that the following analysis also pertains to the case where the utility purchases power from another investor-owned utility. While we refer to IPPs in our analysis, this term is also meant to include other utilities that may sell generating capacity.

Some of these assumptions are probably too extreme. In particular, we invoke the fourth and fifth assumptions to illustrate the conditions that are necessary for there to be a hidden cost of purchased power. Later, we discuss how modifications of these assumptions affect our analysis.

A. Construction and Operating Risks.

Construction risks come about because the final cost of building new capacity is uncertain. While the project has a budget, for various reasons the plant may come in over budget or under budget. In addition, the plant may not be operational in the future. The impact of delays, cost overruns or down time are the same whether they occur during construction or after the plant is running. Thus, for convenience, we refer to operating and construction risks as construction risk.

While IPPs and utilities may use different technologies and thus have different probabilities of cost overruns, the treatment of overruns is symmetrical. Cost overruns and similar losses are not included in the utility's rate base. Thus, the losses from overruns are borne dollar for dollar by the utility investors. Similarly, in most IPP contracts, the utility only pays for power when the IPP's plant is up and running and the price at which the utility buys the power are independent of any cost overruns. Thus, the IPP investors bear the losses dollar for dollar from cost overruns. Since both the utility and IPP investors bear the costs of construction cost overruns, the treatment of these risks is symmetrical.

It is often argued that IPPs can eliminate construction risks by entering into "turn key" contracts with building contractors.[6] The ability to do this does not affect our analysis. It is worth discussing why this does not affect our analysis because the logic is used repeatedly in this analysis. Granted, the IPP does not face construction risks if it enters into a turn key contract. The contractor now bears the consequences of any overruns or delays. However, the contractor will insist on a higher price to build the plant if it is forced to bear this risk. Thus, the IPP does not eliminate construction risk when it enters into a turn key contract, rather it pays the contractor to bear this risk.

Now we turn to the pricing of these risks. In other words, how do construction risks affect the required rate of return on invested capital. Construction cost risk is largely diversifiable in that cost overruns are not correlated to economy wide conditions. Consequently, diversifiable risks probably have a small effect on investors' <u>expected rate of return</u>;[7] however, they do affect the investors' <u>promised rate of return</u> and hence must be recovered in the price charged for the power sold. The following example illustrates this point.

<u>Example 1.</u> Suppose that an IPP or utility is planning to build a plant at a cost of $1,000,000. The only risks associated with building this plant are that the plant may never come on line. Assume that the plant will come on line with a 50% probability and will be a complete failure with a 50% probability. If this risk is diversifiable, then investors must expect to earn the risk-free rate which is 10%. However, the investors only earn a return if the project is successful; thus, they must be promised a 20% return if they are successful. Therefore, they must charge a rate for the power sold which allows them profits of $200,000 per year. If the probability that the plant will not come on line is higher, then the promised rate of return on the investment and the price that must be charged for the power will be higher.

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[6] We might add, of course, that utilities can do this too.

[7] For a discussion of diversifable and non-diversifable risk and expected return on a security, see any standard finance textbook, e.g., Eugene Brigham and Louis Gapenski's <u>Intermediate Financial Management</u>.

The utility does not face construction risks if it chooses to buy purchased power as opposed to building its own capacity. Considering construction risk alone, the choice to purchase power will lower the utility's cost of capital compared to the build alternative. In particular, the utility will have a lower yield on its debt for any level of leverage chosen (including capacity payments to the IPP as equivalent to debt) if it decides to purchase new capacity.

However, if the utility purchases power from an IPP, construction risk is not eliminated; rather it is shifted to the IPP. The IPP investors now bear the construction risk. The IPP investors will build this exposure into the price at which they agree to sell the power. In summary, regardless of whether the new capacity is built by the IPP or the utility, the ratepayers compensate either the IPP or utility investors for bearing construction risks. Ratepayers do benefit in the form of lower rates from the choice to purchase power if (1) IPP bidders are competitive and (2) the IPP has a lower probability of construction cost overruns.

B. Demand Risks.

Demand risk comes from uncertainty about the level of demand for power in the future. If the economy performs well in the future, then the demand for power will be high. Likewise, if migration into the service area is high, demand will be high. Obviously, future economic performance and migration are uncertain especially over the 20 to 30 year useful life of a power plant. Demand risks created by exposure to the level of economic activity are not diversifiable and are therefore likely to have a substantial effect on the expected return that investors demand on securities.

The extent to which the utility investors bear demand risk when the utility purchases power versus builds its own capacity are captured in the following example.

Example 2. A utility has two 400 MW plants that currently run at full capacity. The utility forecasts that demand will increase in the future. However, it is difficult to determine precisely what demand will be. Suppose the utility thinks that future demand will be either 1600 MW or 1200 MW. The utility can either build 800 MW of future capacity or buy 800 MW of future capacity from an IPP.

If the utility builds the capacity and demand turns out to be 1600 MW, then the utility generates at full capacity. If the demand is only 1200 MW then the utility only needs 75% of available total system capacity. 400 MW of the utilities capacity will be unused under our assumptions, and the utility will be unable to put this into their rate base.

If the utility buys the capacity, then it must make capacity payments for 800 MW of power from the IPP regardless of the demand outcome. If demand is 1600 MW, then both the utility and IPP run at full capacity. However, if demand is only 1200 MW then the utility only produces 400 MW at its original plants. Again, the utility has 400 MW of unused power capacity, and again the utility will lose a 400 MW plant from its rate base.

Example 2 shows that the utility bears the risk of the demand shortfall regardless of whether it purchases power or builds its own capacity. However, if it buys its capacity, the shortfall is spread over a smaller asset base. In the above example, if the utility purchases power and there is a demand shortfall, 50% of its power production capital base is no longer used and useful. If the utility builds its new power and there is a demand shortfall, only 25% of its power production capital base is idled. Thus, the risk per dollar of investment in the utility goes up when the power is purchased.[8] This added risk to utility investors is sometimes referred to as the hidden cost of purchased power. This hidden cost will translate into a higher required return on utility securities. Thus, when considering only demand risk, we can say that purchasing power will lead to a higher cost of capital for a utility than will building its own facilities. Also,

[8] Naill and Sharp (1991) argue that the utility faces demand risk regardless of whether it builds or purchases new capacity. They correctly point out that if demand is low, then regardless of whether the capacity is purchased or built, the utility will have excess capacity. However, if the utility purchases power, its risk is spread out over a smaller asset base. Purchased power increases the utility's demand risk per dollar invested.

under our assumptions, if state regulators do not acknowledge any increased risk due to a purchased power contract, utility investors will suffer a loss if the utility purchases power. This occurs because the utility earns no new profits from its purchased power, yet the riskiness of future profits will increase.

Example 2 also shows that while the utility bears all of the demand risk, the IPP bears no demand risk. This implies that IPPs will have a lower cost of capital for financing a new power plant than will a utility. In other words, IPPs will have a competitive advantage, because lack of demand risk translates into lower required returns on capital invested in IPP generating capacity. This also allows IPPs to utilize more debt in their capital structures and benefit from the debt tax shields associated with debt financing. To the extent that the IPPs operate in a competitive market, they incorporate the cost savings from a lower required return in the rate they charge utilities. Since purchased power payments are passed through to consumers dollar-for-dollar, consumers benefit by paying lower rates when a utility purchases power.

The hidden cost of purchased power occurs when the utility bears uncompensated demand risk. It is important to point out that three conditions are necessary for there to be a hidden cost of purchased power. The following discussion states the three conditions and briefly discusses the extent to which they may hold.

First, purchased power contracts must shield the IPP from demand risk. Take-and-pay contracts largely shield the IPP from demand risk. However, many contracts include a clause that gives the utility some latitude as to when it begins to purchase power. This allows the utility some time to wait until demand materializes before it purchases power. Second, the utility must not be able to earn its allowable rate of return on any unused rate base in the event demand is low. In many states, regulators implicitly guarantee that any approved new capacity will remain in the rate base. This may greatly reduce demand risk. However, even if some excess capacity is allowed to remain in the rate base, the utility still bears some demand risk between rate hearings. The demand risk the utility bears between rate hearings is larger if it purchases power.

Third, there is a hidden cost of purchased power only if the regulators do not compensate the utility for additional demand risk. Then the utility investors' claims are worth less if the utility purchases power. If the regulators do compensate the utility for any additional demand risk, then ratepayers bear the risk of purchased power.

We should also add that even if a utility is compensated for the demand risk it bears due to a purchased power contract through a higher allowed return on pre-existing rate base, the IPP still does not bear any demand risk and therefore still has a lower cost of capital than the utility. Thus, all else equal, if there is competitive bidding for new generating capacity, the IPP can make a lower bid than the utility. In other words, the IPP still has a competitive advantage. Section III will suggest ways to eliminate this competitive advantage.

C. Summary.

Given our assumptions, consumers benefit when a utility purchases power rather than builds new capacity. Construction risk is part of building new capacity regardless of who builds the capacity. As is the case in most markets, the ratepayers compensate investors in new capacity (public utility investors or IPP investors) for bearing this risk. The consumer benefits or loses to the extent that the capacity is built by the most efficient power producer.

However, competitive forces may break down with regard to demand risk. Under the conditions described above, the utility bears demand risk. The IPP benefits from the lack of demand risk and passes this on in the form of a lower bid. Thus, the consumer benefits. However, demand risk has not been eliminated; rather it is borne by utility investors. The losers are utility investors <u>unless</u> the utility's cost of capital is adjusted to compensate the utility by allowing higher rates.

This last item is of particular concern to utilities. If purchased power becomes too large a fraction of total power supplies, they will have (1) a diminished rate base through time, and (2) increasing levels of demand risk. As larger amounts of demand risk are spread over a shrinking rate base, the risk of investing in utility securities becomes quite large. Utility investors are hurt unless a higher cost of capital is allowed. Higher allowable rates of return could become politically embarrassing for state utility commissions (e.g., how do you explain that one utility with a large amount of purchased power contracts gets a 17% return on equity while other utilities with less purchased power get a 12% return). This diminished rate base problem is a legitimate concern for utilities that wish to significantly increase purchased power commitments to meet future energy needs.

Our risk analysis highlights an additional point. Whether a utility's securities are more or less risky when new power is built or bought is <u>not</u> the item of primary concern from a regulator's point of view. If construction risk is very large, then clearly the buy decision translates into safer returns to utility investors. On the other hand, if demand risk is very large, then clearly a purchase contract "levers up" the risks associated with new capacity commitments and create greater risks for existing securityholders than expanding the risks over a larger capital base financed at the pre-existing mix of debt and equity.

What is important to regulators is (1) whether one party may be getting a competitive advantage over another party because the parties face a different set of risks or regulations, and (2) whether the parties involved are being fairly compensated for the risks they bear. We have suggested that since IPPs and utilities do not face the same demand risks, each of the above two problems may exist. We now turn to measuring the potential hidden costs of purchased power.

II. Measuring the Hidden Costs of Purchased Power

The hidden cost of purchased power is often discussed in the context of the extent to which the liability associated with a long-term purchased power contract lowers the utility's bond rating. Bond rating agencies emphasize that purchased power results in a decline in coverage ratios. It is a mistake, however, for regulators to focus on coverage ratios.

Bond default risk depends on (1) the ratio of income to fixed charges and (2) the risk of the income stream. As discussed above, purchasing power (as opposed to building power capacity) decreases the risk of the utility's income stream when the reduced construction risk is larger than the additional demand risk. So, a utility facing no construction risk could tolerate a lower coverage ratio than a utility that faces considerable construction risks. Furthermore, if there are commitments by regulators to pass demand risk on to consumers, then the utility can afford even lower coverage ratios.

Regulators should be concerned with assessing the size of the hidden cost of purchased power (i.e., the extra cost of capital due to bearing any demand risk created by a purchased power commitment). Unfortunately, it is very difficult to measure this hidden cost. The example in Appendix A shows how analysts conventionally attempt to measure the "hidden cost" of purchased power.

Consider a regulator forced to evaluate two bids for additional capacity: one by a public utility and the other by an IPP. Suppose the two parties propose to build exactly the same plant. The efficiency of the two plants and the construction risks are identical. In the example, we assume a utility has $1 billion of capacity already. The optimal capital structure is assumed to be 50% debt and 50% equity. It is assumed that equity investors demand a 15% return on equity, debt investors demand a 10% return on equity, capacity depreciates at 5% per year, and the tax rate on corporate income is 40%. We also assume that all utility charges are for the cost of capacity. The required revenue stream for this utility before the build or purchase decision is $225 million in the first year.

Assume that the utility can either buy or build a new plant that costs $500 million to construct. If the utility builds, analysts generally assume that <u>the risk of the new project is the same as risk of the existing projects.</u> So, again 50% debt and 50% equity is used to finance the new project. The capital cost of the new project is $112.50 and the total revenue requirement for new and existing plant is $337.50.

If the firm buys power in a competitive market, analysts implicitly assume that <u>buying power adds as much risk to the utility as building the plant.</u> This, of course, implies that the IPP faces <u>no</u> risk for providing the new capacity through a purchase agreement. Consequently, the project can be entirely debt financed. In a competitive IPP market, the capacity charge will be $50 million of interest (10% of $500 million) plus $25 million of depreciation -- or $75 million.

Now we can see the hidden cost of purchased power as the difference between the utility and IPP's cost of capital: $112.5 million - $75 million = $37.50 million.

This can be seen another way. If the utility purchases power capacity, capacity payments are the equivalent of debt. Since the utility bears all the risk of the transaction, it needs to get back to its target capital structure of 50% debt and 50% equity. Since $50 million of the capacity payments can be viewed as interest payments, the utility must replace $250 million of debt with $250 million of equity to get back to a 50% debt, 50% equity mix. To be fairly compensated for the risk to its security holders, the utility must receive revenues of $337.50 million. This translates into $75 million for the purchased power contract and $262.50 in revenue to cover all other capital costs ($37.50 million higher than before). If, however, regulators do not recognize the added risks, the utility only gets $225 million for its old asset base and $75 million to cover capacity payments - or $300 million. The difference between what it should get and what it gets ($337.5 million - $300 million = $37.5 million) is again the hidden cost of purchased power.

To see the problem with estimating the hidden cost of capital look at the two key assumptions. The first assumption is that <u>the risk of the new project is the same as the risk of existing projects.</u> This is a dubious assumption. Existing capacity is not subject to construction risk and is less prone to demand risk, because assets in place are already serving established markets. In this case, the utility's current cost of capital is smaller than a new construction project's cost of capital. On the other hand, the utility might be involved in some very risky current ventures (e.g., nuclear power). In this case, the utility's cost of capital is higher than the cost of capital of the new project.

The second assumption is that buying power adds as much risk to the utility as building the plant. Again, this is highly unlikely. If it were true, then we would expect IPPs to be 100% debt financed. They are not. Recall from our earlier analysis that the utility is avoiding operating and construction risk by purchasing power. This implies that the hidden cost of capital is overstated in this analysis. In other words, the revenue requirements of the IPP would be higher than $75 million, and the revenue requirements for the utility above and beyond its capacity payments would be less than $267.5 million.

This leads us to a final point. Even if actual observed costs of capital for IPPs include whatever risks they are bearing, it is still not appropriate to use the difference between the existing average cost of capital of the utility and the average cost of capital for the IPP multiplied by the capital investment in new plant as the cost of hidden cost of bearing demand risk for two reasons. First, the existing cost of capital for a utility (and perhaps IPP) is not likely to equal the marginal cost of capital for a generation project. Second, differences in borrowing costs may be for reasons totally unrelated to "the hidden costs" of bearing demand risk. For instance, suppose that the IPP is capable of building new capacity with lower construction or operating risks than the utility. Access to a more reliable technology means less probability of default and lower borrowing costs.

In summary, while we believe that the utility may face uncompensated demand risk and hence that there may be a hidden cost of purchased power, we do not believe that comparing the utility and IPP's average cost of capital accurately measures this hidden cost. While regulators should look at the extent to which they compensate utilities for any additional demand risk they bear, they cannot simply rely on the differences in IPP and utility costs of capital as evidence of the size of the hidden cost of purchased power.

III. Creating a Level Playing Field.

The analysis under our present set of assumptions illustrates that competitive bidding for purchased power is potentially biased in favor of IPPs. The advantage is due to the fact that IPP investors are not required to bear demand risk. Thus, all other things equal, the IPP will have a lower cost of capital for financing a generation project compared to an investor owned utility. It is important to stress that the IPP's advantage only comes about because the IPP is not forced to bear demand risk.

To eliminate this advantage, either the risks borne by IPPs and the utility must be equalized <u>or</u> bids must be adjusted to include the cost differential between utility and IPP bids attributable to demand risk. This section addresses four methods by which a level playing field can be provided for bidding between IPPs and investor owned utilities. We also discuss the desirability of each method. The four methods are: (1) adjusting the capital costs of bids to reflect the "hidden" cost of purchased power, (2) transferring all demand risk to customers, (3) writing purchased power contracts that force IPPs to assume demand risk, or (4) allowing unregulated utility-owned power generating subsidiaries that are separately capitalized to bid on power contracts on the same terms as IPPs. Our conclusion is that the last method is most desirable.

1. Adjusting for Demand Risk

A seemingly simple method of leveling the playing field is to compare the rates of the IPP and utility with adjustments made for differential cost of capital induced by the IPP's lack of demand risk. Practically speaking, however, as the previous section illustrated, this method could be difficult to implement because of a very large disagreement about how much demand risk there is and how much that demand risk affects a utility's cost of capital. Measuring the extra cost of financing a project due to demand risk is a very difficult task for a myriad of reasons. The IPP's advantage (lack of demand risk) cannot simply be measured by comparing the IPP's cost of capital to the utility's current cost of capital. In short, we believe this is not a workable solution.

2. Transfering Demand Risk to Consumers

A second method to level the playing field is to equalize risk-bearing between IPPs and utilities by forcing utility customers to bear demand risk whether the utility builds or purchases power. If ex-post there is too much capacity, the utility must be allowed to keep excess capacity in its rate base and still pass through all the costs of purchased power. There are two ways that demand risk can be passed on to consumers. First is the traditional rate base method. If the capacity is utility owned, regulators determine electricity rates that are expected to allow the utility to recover capital costs on all its plants and facilities. If the capacity is IPP owned, then regulators determine rates that again are expected to allow the utility to recover fixed capacity charges that must be made to the IPP. Note that this rate base method does not totally eliminate demand risk faced by the utility. If electricity usage is lower than expected, the utility will not generate sufficient revenue to cover their costs until a new rate hearing is set. Consequently, the utility still bears some (though considerably less) demand risk.

A second method is to allow capacity charges for both utility owned capacity and IPP purchase contracts to be recovered in the same way as a fuel cost adjustment clause- in short, a capacity cost adjustment clause. Rates or charges to certain customer classification groups can be altered on a continuous basis. If usage is lower than usual, rates per kilowatt hour (or flat fees allocated to different customer groups) can be raised to totally recoup capacity costs. To keep the playing field level, there must be a capacity adjustment clause regardless of the power source, IPP or utility owned.

Currently, Florida has adopted a capacity adjustment clause through the Florida Public Utility Commission's Order No. 25733. Order No. 25733 goes a long way toward equalizing demand risk; however, it is not clear whether the order constitutes a binding commitment on the part of regulators. Politically, standing by a full cost recovery commitment could prove very difficult, as evidenced by the frequent disallowances of excess capacity throughout the 1980s. If rates rise as a result of a large amount of excess capacity, commissions may be tempted to make more forceful challenges of what constitutes "prudently" incurred costs. Just the fear of this sort of conduct could result in higher capital costs for utilities, because capital markets might perceive that demand risk still exists. So, unless investors can be convinced that capacity cost adjustment clauses are firm commitments, this means of equalizing the cost of capital between IPPs and utilities may be ineffective.[9]

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[9] John Seelke points out that Florida's regulatory treatment of capacity charges may solve the "hidden cost" of the purchased power problem.

Forcing ratepayers to bear demand risk has three drawbacks. First, from a risk sharing perspective it does not make sense to subject ratepayers to potentially large fluctuations in rates charged. Utilities and IPPs have access to public capital markets and can spread risk out among well diversified investors. Second, in the event of inadequate demand, if unused capacity is allowed in the rate base, utility rates could far exceed the marginal cost of the service, thus distorting the power utilization decisions of customers. Third, utilities may lose their incentive to make accurate forecasts of future demand patterns because they are fully compensated for their mistakes. Recall that any attempts to charge an ex-post lack of prudency in forecasting brings back the problem of administrative finality.

3. Shifting Demand Risk to the IPP

A second method to equalize the demand risk borne by the IPP and utility is to mandate contracts between the IPP and utility that force the IPP to bear demand risk. To see how this could be implemented, consider Example 2. In this example, if the utility buys additional capacity from an IPP and demand turns out to be low, then the utility can reserve the right to make capacity payments for only 400 MW of power rather than 800 MW of power from the IPP.

If purchased power contracts are designed in this manner, the IPP's capital cost advantage is eliminated. However, there are two practical problems with this proposal. First, as is the case when consumers bear demand risk, if the IPP is forced to bear the demand risk, then the utility has less incentive to provide accurate forecasts of future demand.

Second, such contracts are difficult to enforce if demand is difficult to measure. The utility has an incentive to "hold-up" an IPP after the power plant is built by claiming that cheaper power is available elsewhere or the utility can threaten to meet the demand from its own production facility (perhaps at higher cost) unless the IPP lowers previously agreed upon rates. IPPs may be reluctant to enter into any purchased power contract without a take-and-pay structure. This problem could be eliminated if the utility is allowed to renege on its agreement to buy power only if part of its rate base is disallowed due to excess capacity.[10]

4. Separately Capitalized Utility Subsidiaries

Our favored method to level the playing field is to allow utilities to bid for power contracts under the same terms as IPPs. This is accomplished by allowing utilities to set up separately capitalized and unregulated subsidiaries to undertake specific power generation projects in competition with IPPs. If the utility subsidiary is treated as an independent entity, then it will face the same risks as the IPP. Since, the utility subsidiary faces the same risks as the IPP, it is not at a competitive disadvantage.

The real advantage of this scheme, however, may not be a level playing field for project financing, but a level playing field in terms of regulatory treatment. For instance, a utility subject to cost of service regulation is less likely to recover any benefits associated with the more efficient delivery of a service. This creates a potential competitive advantage for IPPs. If an IPP can come in under cost, it can keep the difference between expected costs and actual costs. Since it can keep efficiency gains, IPPs may submit lower bids because of the superior incentives they have to cut costs. Utilities may come in with higher bids, because they realize that any amount they come in under cost may wind up being rebated to utility customers. If the utility can set up an unregulated subsidiary, this competitive disadvantage can be eliminated.

[10] This rule may result in regulators disallowing capacity that is not owned by a party that it has repeat transactions with.

Differential regulatory treatment can also cut against IPPs. A potential competitive disadvantage for IPPs may arise from the need to make plant alterations that are mandated by state or federal law. For instance, if a utility must make plant modifications to comply with environmental standards or laws like the American Disabilities Act, they are generally allowed to put the alteration costs to plants into their rate base. IPPs are not afforded this luxury. They must get contractual provisions in the purchase contract to compensate them for any such potential costs. If all such future costs are hard to quantify contractually, then IPPs may be forced to make higher bids to compensate for these potential future costs, whereas an unregulated utility may not.

Competitive bidding between unregulated utility subsidiaries and IPPs has the virtue of equalizing risks to the bidding entities and equalizing regulatory treatment. This suggests that winners and losers are more apt to be determined on the basis of who can construct and operate a plant most efficiently. Ultimately, consumers benefit because the low cost bidder tends to win the bidding.

Two further aspects of a bidding system need to be addressed. First, bidding requires an outside referee to evaluate the bids. Utilities may have an incentive to pick their own subsidiaries as the winner even when their subsidiary is not the low cost bidder. For example, the utility may have a preference for size or it may be concerned that it will not be fully compensated for the extra risk being spread over a shrinking rate base. State regulatory commissions will have to assume this referee's role. The referee's role can be made easier by specifying a fairly uniform contractual form that puts a limit on capacity, but allows different fuel sources in the bidding. The bids can then be evaluated primarily on the bid price.

When utility subsidiaries are allowed to compete, demand risk is still an issue to the utility holding company, but it does not give a competitive advantage to any bidding party. If the utility holding company's cost of capital is not adjusted, the utility subsidiary could win the bidding, but the utility investors are hurt by the uncompensated demand risk. Bidding by a utility subsidiary (1) gives a clearer picture of the subsidiary's project costs versus the IPP's and (2) gives the subsidiary a chance to compete as an unregulated entity.

IV. IPPs, Leverage and System Reliability.

Critics of purchased power are concerned with the reliability and efficiency of power systems when power decisions are not under the complete control of one entity. For instance, will IPPs complete power projects on time? History suggests no real problem. Further, the IPP contracts have performance bonds which give the IPP a strong incentive to complete projects on time.

Further, some raise the concern that IPP's reliance on financial leverage may jeopardize their reliability. For example, Kahn et al. (1992), referring to highly leveraged IPPs, claim that "all else equal, a highly leveraged project has a narrow margin between revenues and costs. Unanticipated operating problems may eliminate that margin and cause the project to cease operation."[11] We agree that highly leveraged projects have a narrow margin between revenues and costs due to their high leverage and thus are more likely to become financially distressed. However, we do not agree that financial distress is likely to cause the project to cease operations.

[11] See "Analysis of Debt Leveraging in Private Power Projects" by Edward P. Kahn, Meg Meal, Siegfried Doerrer and Susan Morse, Energy & Environment Division, Lawrence Berkeley Laboratory, University of California, August 1992.

If the project no longer operates, then it is liquidated and the proceeds of the liquidation are paid out to the financial claimants. If the firm has no debt claims, its owners (equity holders) will find it in their best interests to liquidate only if the firm is sufficiently unprofitable that its liquidation value exceeds its ongoing concern value. To a large extent, the IPP lenders face the same liquidation versus continuation incentives as the equity holders of an unleveraged firm. The lenders will not foreclose on the IPP debt simply because the IPP has failed to meet its financial obligations. The lenders will only foreclose if the IPP is sufficiently unprofitable that its liquidation value exceeds its ongoing concern value.[12]

It is also unlikely that purchased power will add to the problems of utility planning and coordination. Purchased power contracts can be easily designed to give IPPs and utilities the incentive to cooperate with regard to planning and coordination. For instance, if it turns out that the utility can save money by cutting back on IPP production, it could reduce its payments to the IPP by the marginal cost of the IPP producing the extra power. This results in an efficient production mix without unfairly damaging either party. In fact, most purchased power contracts only obligate the utility to pay the IPP capacity costs. If the utility does not purchase power, the payments to the IPP are reduced by the marginal cost of producing the power. In summary, if there is money to be saved by altering production plans, there is no reason why side deals cannot be struck with the IPP as if the IPP were part of the utility's holding company structure.

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[12] The lenders have an incentive to foreclose their loans to an IPP whose ongoing concern value exceeds its liquidation value when the liquidation value is greater than the face value of the debt claims. However, for a highly leveraged IPP this condition is unlikely to be met.

V. Recommendations of the Florida Public Service Commission Staff.

The most recent recommendation of the Florida Public Service Commission Staff with regard to purchased power (Docket No. 921288-EI, May 6, 1993) stipulates that utilities contemplating purchased power must provide "a discussion of the potential for increases or decreases in the purchasing utility's cost of capital, the effect of the seller's financing agreements on the purchasing utility's system reliability, and any competitive advantage to the seller resulting from the sellers financing arrangements." Our analysis has touched on these issues.

First, the buy-versus-build choice clearly affects the utility's risk and hence cost of capital. If the utility purchases power by entering into a long term agreement to purchase power, then it clearly takes on additional demand risk, but reduces its exposure to construction risks. If the utility builds, it takes on demand and construction risks but spreads these risks over a larger asset base. Thus, it is not clear if the utility's cost of capital will be higher or lower if it purchases power rather than builds new plants.

Nevertheless, this is not the central issue. The central issue is whether IPPs get a financing advantage because they do not bear demand risk that utilities bear. The answer, of course, is it depends. If Florida's utility commission will truly guarantee recovery of capacity charges in the event of demand shortfalls, the problem is largely mitigated. If these guarantees are shaky, then utilities are at a competitive disadvantage with respect to financing. We also suggest that there may be other disadvantages associated with being a regulated entity. Consequently, we recommend that deregulated and separately capitalized subsidiaries be allowed to participate in regulator referred competitive bidding for generation facilities. This allows them to compete on the same level as IPPs.

Finally, we are not overly concerned about issues of system reliability with respect to highly levered IPPs. Market forces will give IPP investors the correct incentives to set up management structures that deliver reliable and efficient services.

Appendix
Impact of Purchased Power

Assumptions:

Initial Rate Base of $1 billion
Optimal financing for utility 50% debt and 50% equity

Rate on Debt:	10%
Rate on Equity:	15%
Tax rate:	40%
Depreciation:	5% per year

Revenue Requirements if Build $500 Million Plant

	Existing Assets	Build A	Total
Equity	75	37.5	112.5
Interest	50	25	75
Taxes	50	25	75
Depreciation	50	25	75
	$225	$112.5	$337.5

Revenue Requirement if Purchased Power in Competitive Market for Power: Assumes Firm then Recapitalizes back to Equivalent of 50% Debt and 50% Equity.

	Existing Assets	Purchase Contract	New Financing of Existing Assets	New Total
Equity	75	---	112.5	112.5
Interest	50	---	25	25
Taxes	50	---	75	75
Depreciation	50	---	50	50
Capacity Payment with Competition	--	75	---	75
	$225	$75	$267.5	$337.5