Peter Cramton is Professor of Economics at the University of Maryland and Chairman of Market Design Inc. Over the last 20 years, he has published research on auction theory and practice in the leading peer-reviewed economics journals. During the last 12 years, he has applied this research in the design and implementation of auction markets worldwide, especially in North America and Europe. He has led the design and implementation of dozens of high-stake auctions in the energy and telecommunication industries. He has advised over 26 companies on bidding strategy in energy and telecommunication auctions. Since 1998, he has advised ISO New England on electricity market design, and with Steven Stoft led the design of the proposed forward capacity auction in New England. He received his B.S. in Engineering from Cornell University and his Ph.D. in Business from Stanford University.

Professor Peter Cramton
Economics, Tydings Hall
University of Maryland
College Park MD 20742-7211

cramton@umd.edu
voice/fax 240-396-1043

Steven Stoft is an independent consultant. He is the author of *Power System Economics: Designing Markets for Electricity* (Wiley-IEEE, 2002). He has been an advisor to PJM's Market Monitoring Unit since 1999. He was an expert witness for the California Electricity Oversight Board and the California Public Utility Commission in the Long-Term Contract Proceeding before FERC, and for ISO New England in their LICAP proceeding, also before FERC. With Peter Cramton he led the design of the proposed forward capacity auction in New England. He received his B.S. in Engineering Math and his Ph.D. in Economics from the University of California at Berkeley.

Steven Stoft
2910 Elmwood Court
Berkeley CA 94705

steven@stoft.com
510-644-9410

"We're at the home of Jim and Mindy Marks, who are about to discover that their utility bill has gone sky-high. Let's watch."

Uniform-Price Auctions in Electricity Markets

Peter Cramton and Steven Stoft[1]

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Abstract

Wholesale electricity markets are commonly organized around a spot energy market. Buyers and suppliers submit bids and offers for each hour and the market is cleared at the price that balances supply and demand. Buyers with bids *above* the clearing price pay that price, and suppliers with offers *below* the clearing price are paid that same price. This uniform-price auction, which occurs both daily and throughout the day, is complemented by forward energy markets. In practice, between 80 and 95 percent of wholesale electricity is traded in forward energy markets, often a month, or a year, and sometimes many years ahead of the spot market. However, because forward prices reflect spot prices, in the long run, the spot market determines the total cost of energy. It also plays a critical role in the least-cost scheduling and dispatch of resources, and provides an essential price signal both for short-run performance and long-run investment incentives. Arguments that the uniform-price auction yields electricity prices that are systematically too high are incorrect. However, insufficiently hedged spot prices will result in energy costs that fluctuate above and below the long-run average more than regulated prices and more than is socially optimal. Tampering with the spot price would cause inefficiency and raise long-term costs. The proper way to dampen the impact of spot price fluctuations is with long-term hedging. Although re-regulation can provide a hedge, there are less costly approaches.

Introduction

Recent large electricity price increases have led some to conclude that wholesale electricity markets have failed. The uniform-price auction, used to balance supply and demand in the spot energy market, is often suspected as the culprit.[2] In this spot market, buyers and suppliers submit bids and offers for each hour and the market is cleared at the price that balances supply and demand. Buyers with bids at or above the clearing price pay the clearing price for the quantity purchased. Suppliers with offers at or below the clearing price are paid the clearing price for the quantity sold. Thus, a nuclear supplier with a marginal cost of $20/MWh would be paid $80/MWh for its quantity sold in the spot market, whenever the clearing price happened to be $80. Indeed, all suppliers are paid the *highest* variable cost among all those supplying spot energy.

Doesn't such a system cause consumers to systematically overpay for electricity? *Absolutely not*. Indeed, the clearing-price auction is an essential feature of any electricity market designed to reliably provide consumers electricity at minimum cost. The clearing-price auction plays a critical role in the least-cost scheduling and dispatch of resources, and provides an essential price signal both for short-run performance and long-run investment incentives.

What then is responsible for the recent large increases in electricity prices? This is an important question and deserves an answer that goes deeper than an examination price formation in the spot market. Several long-run issues must be understood before the role of the spot market can be correctly evaluated. Without this, there may be an incorrect assignment of blame and recommendations for changes that would prove costly in the long run. These are the factors—from most important to least important—at work in the present situation.

1. Fuel prices increasing sharply
2. The removal of some retail price caps, an artifact of restructuring settlements
3. Changes in relative fuel prices, resulting in short-run disequilibrium
4. Insufficient long-term forward contracting
5. The law of one price
6. The uniform-price auction used in the spot market

The first three factors are the drivers of present market developments; the last three concern the way the market responds to external forces. Rather than begin with an examination of a uniform price action, it is better to examine first why this has become a concern. A stylized description of recent events will serve to highlight the principles involved and explain the main effects. Since electricity markets opened in 1998, the power industry has developed as follows.

Stage 1: Overbuilding followed by high gas prices. At first, gas prices were low and gas-fired generation appeared cheaper than alternatives. In a competitive market, this opens the door to high profits for companies that build new gas-fired plants. But this door will only stay open until a new equilibrium with sufficient gas generation has been reached. This led to a flood of new gas-fired plants. But investors soon faced two unpleasant surprises. Wholesale prices were kept lower than they expected and gas prices shot up. The result was a complete reversal. There are now too many, not too few, gas-fired plants and they are relatively expensive, not relatively cheap.

The new disequilibrium produces new winners and losers. First, owners of gas-fired plants are clearly hurt. There is too much capacity and wholesale prices have been suppressed by mitigation rules. The result is that gas-fired plants recover little of their fixed costs and experience a windfall loss. This loss is a windfall gain for consumers. Because gas prices are high and because the wholesale price is frequently set by gas plants, cheaper plants, nuclear and coal plants, experience a windfall gain. When the wholesale price is $80, those with $20 variable costs collect $60 towards their fixed-cost recovery. This has proved to be more than enough. This windfall gain to baseload plants is a windfall loss to consumers.

So far, the net impact on consumers is unknown. Two effects have worked in favor of consumers: (1) the market has been overbuilt, and (2) market rules have held peak prices somewhat below a long-run competitive level. But the disequilibrium effect has worked against consumers. It seems likely that at first consumes received a net benefit, but are now on the losing end of the cycle. But markets are never static, and this is changing. The market is signaling for the *entry* of new baseload plants, but for a *halt* to gas-fired plant construction. In reality, the construction of new baseload plants will be slow, but the halt of investment in new gas-fired plants was quick and complete. The net result will be a tightening of supply and an increase in wholesale prices.

This price increase, due to a tightened supply, has as yet had little impact. Instead the current price increases are driven by increased fuel costs and changes in regulated retail price caps. These changes are readily understood, and consequently this paper will continue to focus on the deeper economic issues, which are pertinent to the controversy over the uniform-price spot market.

Stage 2: High gas prices without surplus capacity. In the coming stage of the market, we cannot be sure of the price outcomes, but it is entirely possible that gas-fired plants will again break-even, baseload plants will increase their windfall gains, and consumers will suffer windfall losses for some time to come. This will only exacerbate present difficulties. That outcome could result from the following dynamic. New capacity will be needed to match load growth. If there are barriers that slow the entry of baseload plants, the new entry will need to be gas-fired peakers and shoulder plants. These will only enter if the current and future profitability of gas-fired plants increases to the break-even level. The new ICAP market rules will allow this, and thereby prevent a shortage of capacity and blackouts, but in doing so, they will raise revenues for all types of plants, peakers, shoulder, and baseload.[3]

There is no certainty this will happen, and this paper is not predicting it, but simply pointing out that it is possible. This possibility is relevant because it is apparently the essence of the fear behind the criticism of uniform spot prices. By making it explicit, that fear can be addressed analytically. The problem, then, is that the market could, for a few years, produce an outcome in which consumers experienced a windfall loss as the result of nuclear and coal plants experiencing a windfall gain. This raises a number of questions that have not been well addressed in the discussion of deregulated electricity markets. Are windfall gains and losses for consumers a normal part of a well functioning market? How should these be controlled? Are the windfalls of Stage 2 the result of a well-functioning market, or of market flaws? Short versions of our answers may be helpful before delving into the analysis.

1. Well functioning markets do produce windfall gains and losses for consumers as well as for suppliers. On average, consumers pay only long-run cost, neither more nor less.
2. Windfalls can be controlled as well in a market setting as in a regulated setting. This is done with long-term contracts.
3. The windfalls of stage two are due to insufficient long-term forward contracting, and may be exacerbated by barriers to entry against certain types of plants.

Spot markets, forward markets, and uniform prices

The hypothetical Stage 2 outcome, with windfall profits for baseload plants, is primarily the result of fundamental economic forces. The relative prices of gas and coal, and of gas and uranium changed dramatically in a short time. In a market with long-term capital assets and incomplete hedging, such price changes produce a windfall for the supplier using the fuel type that has gained the advantage. This has nothing to do with the intricate details of the spot market.

In part, this is a benefit of a market. It pays extra profits to those who invest in the low-cost technology, in this case, new nuclear or coal plants. This stimulates good investment and lowers long-term costs. *It is essential that the spot market operate in this way*; otherwise investors will have no reason to choose wisely. The agreement on this is near universal. But what is the implication for existing plants? Does the spot market need to pay windfall profits to existing plants or only to new investments?

*Separating existing from new***.** It is necessary for better plants to be more profitable, otherwise the market can provide no guidance for building better plants. But once they are built, it may seem unnecessary to continue this guidance. This is the seeming paradox at the heart of the sensible question concerning a uniform-price spot market. There is also another question which causes confusion: Why shouldn't we try to hold everyone's spot price down to their variable cost. This will be taken up in detail later, but the answer is virtually self-evident—because no investor would ever build a plant if fixed costs were not recovered. When the market is in equilibrium, uniform prices simply cover variable plus fixed costs. That cannot be argued with. But the question of paying windfall gains through a uniform-price spot market is much deeper, and deserves serious attention.

Suppose we have a power market that is competitive, well designed with a uniform-price spot market, and in equilibrium with respect to the types of generating capacity that it has in place. It will pay all plants just enough to cover their fixed and variable costs. Now suppose the price of gas quadruples and all gas plants are on the margin, and so set the spot price, one-half the time. This will not help gas plants, which face much higher fuel costs, but it will raise revenues for nuclear plants enormously without any corresponding increase in production costs, because the price of uranium is unrelated to the price of gas. What should be done about this? Two courses of action are suggested: (1) pay nuclear plants less than the market-clearing spot price, or (2) remind under-hedged load serving entities (LSEs) that they should have more long term contracts. If most LSEs are not well hedged, this may be a painful choice, but it is the choice we must examine.

Consequences of price discrimination. Ignore the possible legal problems (antitrust laws prohibit price discrimination in wholesale markets), and consider a discriminatory spot market in which nuclear plants would be paid only enough to cover their fixed and variable costs. This might be done by capping their spot price at the level the price would have been without the gas price increase. Although that is not easy, for simplicity let us assume it is possible. What are the consequences? First, in the short-run, there is certainly no problem. Existing plants will more than cover variable costs, and so will still have an incentive to provide electricity. Second, existing nuclear plants will continue to earn a normal rate of return, despite the high gas price.

However, it is insufficient to focus solely on the short run. Markets must also provide the right incentives for long-run investment. What will happen in the long run? That depends on the unspoken part of this new policy of capping profits at a normal level. What will be done when things go the other way for nuclear plants and they come on hard times? What if gas prices, rather than quadrupling, are halved? Again two possibilities must be considered: (1) their spot prices will be adjusted up above the market-clearing prices so that their profits stay at the normal level, or (2) they are given the market-clearing price and suffer a windfall loss.

But now we see the problem. Holding their profits constant by always adjusting their spot price is just rate-of-return regulation. Regulating all nuclear plants so that they always make a normal rate of return will completely remove the market's investment signals. Investors will know that no matter how many such plants have been built they can always build one more and make what the regulator has determined to be a normal rate of return. Hence, if investors like this rate of return, they will just keep building, and if they do not, they will not build any more. This will force the regulator to take over the investment decision, and a principal benefit of moving to competitive electricity markets would be lost. This shows that preventing the signals of a uniform-price spot market, if done carefully, simply leads back to rate-of-return regulation.

One caution is in order and it foreshadows the coming analysis. If the nuclear plant has sold its power under, let us suppose, a ten-year contract for differences, for the original equilibrium average price, then imposing a regulated low spot price will impose on it an enormous windfall loss. Its customer will be paying high spot prices, and the nuclear plant will have to make up the difference between those and the contract price while not getting paid the high spot price itself. This could be remedied by having the regulator take over the contract.

The second option for price discrimination is to cap the nuclear unit when it would make excess profit and pay it the uniform spot price when it would suffer a windfall loss. Under such a policy no investor will ever build a nuclear plant. They will know that the regulator will take their windfall gains and let them keep their windfall losses. Moreover, investors in every other type of plant will expect that if they make windfall gains, the same policy will likely be applied to them. Such a policy is much worse than either regulation or a competitive market. The result under such a policy is that the government is forced to purchase all new generating capacity, and in the long-run the electricity industry becomes a state-run enterprise.

Consequence of forward contracting. Long-term forward contracting is a more subtle approach to the problem. First consider what happens if existing nuclear plants have complete forward contracts. Suppose they have signed contracts with LSEs selling their average annual output for as long as the plant remains operational at the average price they receive in the ideal equilibrium before the gas price increase. In this case, existing nuclear plants will not profit at all from the gas price increase. This is the same as under the price discrimination proposal. But for new investors, there is a world of difference. Once the gas price goes up, a new investor can go to an LSE and offer to sell power from a new nuclear plant at a higher price than is charged by existing nuclear plants, but at a lower price than will be charged by gas plants. If there is only one nuclear investor, that investor can capture the entire windfall profit stream from the higher spot prices due to the gas-price increase. This provides a huge incentive for new investment.

So, with complete forward contracting, existing plants capture no windfall profits, but new plants can potentially capture up to all of them. What will happen? With more than one investor there will be competition and the price of power from the new nuclear plant will be bid down. With enough competition it will be only the slightest bit higher than the price of power from an existing plant. With complete forward contracting and near-perfect competition, there is no extra profit for nuclear plants, new or existing. In spite of this, the potential for nuclear profits if there is no new nuclear investment is so great that it assures investment—unless there is some strong barrier to entry. Hence, with complete forward contracting, the market does just what we want.

Let us look more closely at the uniform-price spot market. When gas prices go up, the spot price goes up, and nuclear plants are paid more whenever gas is on the margin. But since the plants have already sold their power, they cannot pocket the higher prices, but must use the extra revenue to make their customers whole. They may sell the power to customers directly at the low long-term price determined by their own costs. Alternatively, their customers may buy from the system operator at the high spot price, and the plant may sell at the high spot price, and then pay their customer the difference between the high spot price and the low long-term contract price. Either way, the existing nuclear plants make no windfall profits.

What if there are no forward contracts? Without forward contracts, does a uniform-price spot market over-charge consumers? Not on average. If the spot market provided suppliers with windfall profits on average, investors would be delighted and build plants with exuberance. We saw this in the early days of the market and the result was low profits or losses. This is the paradox that makes markets work. If profits are high, then profits will fall in response to entry. If they are low, no investor will enter and profits will rise in response to growth in demand. The result is that spot-market profits bounce around a bit, but they cannot be persistently high or low—on average the spot price is just right. However, there are two exceptions: (1) spot prices can be persistently too high if there are significant barriers to entry—then existing suppliers can enjoy windfall profits that correspond to the cost required to overcome the entry barrier, and (2) spot prices can be persistently too low if there are significant subsidies to suppliers of electricity. The result is that, absent entry barriers or subsidies, the suppliers will not, on average, make windfall profits, and consumers will not, on average, have windfall losses.

So, on average, the uniform spot price will be fair to both consumers and suppliers. What then, is the need for forward contracting? Forward contracts eliminate risk for both suppliers and consumers. They provide mutual insurance. If the nuclear plant is lucky and the consumer unlucky, the plant gives its winnings to the consumer. If the consumer is lucky and the plant unlucky, the consumer gives its winnings to the plant. In this way both are insured, and total risk is reduced. The reduction can be dramatic. Both consumers and investors view risk as a cost, so reducing both their risks reduces their costs. Competition will pass the cost savings on to consumers and leave suppliers, as always, with a normal rate of return that simply covers all their costs including the (reduced) cost of risk and normal fixed and variable costs. Hence consumers will find themselves with less risk and with more money in their pockets. This is one reason forward contracts matter.

The second reason lies a bit outside the scope of normal economics. Without forward contracts, consumers will, sometimes for years, experience below-long-run prices. This can happen for example when the market is overbuilt. They will become used to these and they will consider them the “right price.” Then when their windfall losses come, there will be much noise and commotion, accompanied by the perfectly correct observation that prices are above the long-run average because certain plants are making windfall profits. The result will be attempts to interfere with the market design, quite likely by attacking the policy of a uniform spot price. On a particularly disruptive path, this may lead back toward regulation or may simply break the market’s investment incentives and require high risk premiums to maintain reliability.

Does Regulation Handle the Problem Better? Regulation is a kind of long-term contract and consequently it has wonderful risk-reducing properties. Regulated costs may be too high, but there will be little profit risk and generally less risk of price-shocks for consumers. In terms of risk, it is much like the ultimate long-term contracts described above. Of course in either case one may sign a long-term contract for a technology the turns out to be too expensive, so there is still some risk. When comparing regulation with fully hedged markets, the difference lies primarily in the investment and performance incentives. Here the market has all the advantage.

Although economists like to assume optimal forward contracting because it makes the analysis simpler and the outcome rosy, real markets appear not to conform to this assumption. This presents a problem that cannot be solved analytically, and for which we have little data. If the market will not purchase enough long-term forward contracts, does the cost of additional risk outweigh the gain from better incentives? Generally economists judge the benefits of better incentives to outweigh the cost of additional risk, and choose markets over regulation unless there is some overriding consideration.

If the market path is followed, this analysis leads to one clear positive recommendation. Reduce market risk. This does not mean to reduce performance risk, as that would remove the incentives that are the entire point of using a market. Much risk can be eliminated with a well designed capacity market,[4] but this will not eliminate the risks caused by shifts in relative fuel prices. These risks need to be hedged by long-term contracts between generation and load. Encouraging such contracts is not simple, but it is the proper focus for as long as a market course is pursued. This will improve the market, whereas tampering with the uniform spot price could destroy it.

Changing the energy spot market from uniform-pricing to pay-as-bid pricing does not help, and probably hurts

Some have proposed to replace the uniform-price auction with a pay-as-bid auction. The argument is that with a pay-as-bid auction, a supplier would be paid an amount that more closely corresponds to the supplier's cost. Thus, a nuclear unit with a marginal cost of $20/MWh would be paid something closer to $20, even when the clearing price is set by a gas unit with a marginal cost of $80/MWh. Such an outcome is simply wishful thinking; it would only occur if the nuclear unit were forced to offer at $20/MWh, rather than a profit maximizing offer, which would be much closer to $80 than $20, if a pay-as-bid auction were used.

The benefits of a uniform-price auction in organizing trade between buyers and sellers is well understood. Absent market power, the uniform-price auction yields a competitive equilibrium, and the competitive equilibrium is efficient: the outcome maximizes social welfare. At least in theory, the right quantity of electricity is produced by the least-cost suppliers, and this electricity is consumed by the buyers that value it the most.

Of course, real markets, including electricity markets, do not achieve the ideal of perfect competition, but there is a substantial body of theoretical and empirical work that shows that the convergence to full efficiency is rapid as a market becomes more competitive.[5]

Despite these virtues of a uniform-price spot market, can't prices be reduced by a switch to pay-as-bid pricing? This question has been a frequent source of debate and study by economists. In a nutshell, here are the theoretical, empirical, and practical answers.[6]

The theoretical answer is ambiguous. It depends on the particulars of the model. However, in the simplest cases, the answer is that it makes no difference. Both uniform-price and pay-as-bid approaches result in the same expected prices.

The empirical answer is consistent with theory. It depends on the particulars of the setting. However, the overwhelming evidence is that to the extent there are any differences in expected prices the differences are typically small and often insignificant.

From a practical perspective, there are a number of reasons that in the setting of electricity spot markets, uniform-pricing should be preferred.

First, the electricity spot market is a two-sided market in which both suppliers and demanders bid. The uniform-price auction has an obvious virtue in that the money paid by demanders is exactly equal to the money received by suppliers. In contrast, with the pay-as-bid format, the wedge between the winning demand bids and the winning supply offers is extra money paid by demanders, but not paid to suppliers. What is done with this extra money? In the UK, which is the only market we are aware of that uses pay-as-bid pricing, the extra money is whimsically called "beer money." Although this "beer money" has steadily shrunk since pay-as-bid pricing was introduced, suggesting the law of one price is at work, it remains surprisingly large. However, closer examination of the market reveals that the source of the significant spread between seller offers and buyer bids are artificial transaction costs in the UK spot market intended to discourage its use.

Second, pay-as-bid pricing causes profit maximizing suppliers to estimate the clearing price and bid as closely to the clearing price as possible, whenever the clearing price is above the supplier's variable cost. The result is as-bid supply schedules that are all very flat and close to the expected clearing price. The problem is that there is uncertainty in the supplier's estimates of prices. Sometimes a low-cost supplier bids higher than a high-cost supplier, so that the high-cost supplier is asked to supply and the low-cost supplier is not. This happens because the supplier's bid has much to do with its guess about the clearing price and little to do with its cost. In contrast, with uniform-pricing, the primary determinant of a supplier's offer is the supplier's marginal cost. As a result, dispatch inefficiencies are much more common under pay-as-bid pricing than under uniform-pricing. In the long-run, dispatch inefficiencies raise costs, and these higher costs are ultimately passed on to consumers.

Third—and most subtle—uniform pricing is procompetitive in the following sense. With pay-as-bid pricing, the bidder's incentive is to bid as close to the clearing price as possible. Indeed, the pay-as-bid auction may be renamed "Guess the Clearing Price." The pay-as-bid auction rewards those that can best guess the clearing price. Typically, this favors larger companies that can spend more on forecasting, and are more likely to set the clearing price as a result of their size. In sharp contrast, uniform pricing favors the smaller companies (or those with small unhedged positions going into the market). With uniform pricing, the big suppliers make room for the smaller rivals. The small suppliers are able to free-ride on the exercise of market power by the large suppliers. Thus, the exercise of market power with pay-as-bid pricing, because it favors larger bidders, will tend to encourage consolidation and discourage entry; whereas the exercise of market power with uniform pricing encourages entry and reduces concentration. As a result, the market may evolve to more competitive structures under uniform pricing. This self-correcting feature of uniform pricing is especially valuable in markets like electricity that are repeated regularly.

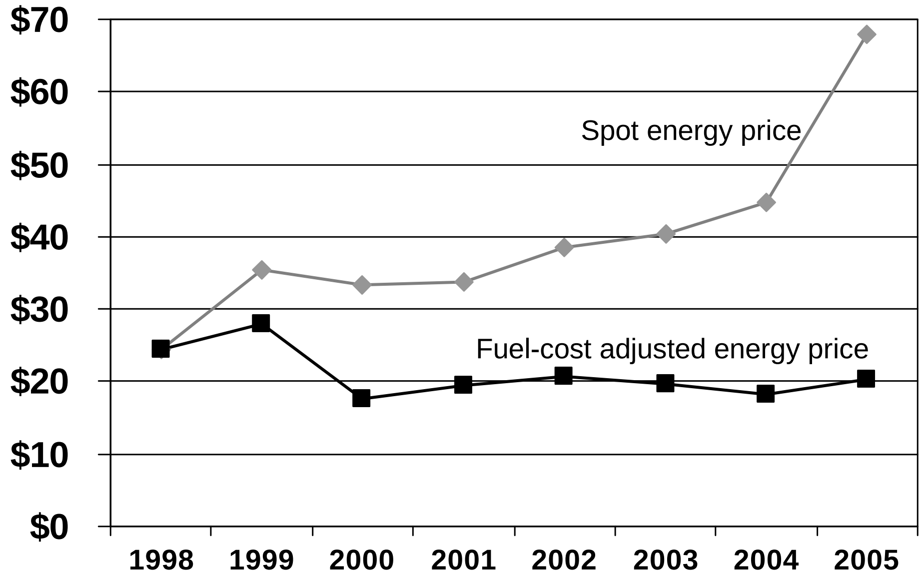
A final nail can be driven in the coffin of pay-as-bid optimism by considering the long run. Suppose the clearing price was so hard to guess that baseload plants guessed 20% lower than the actual clearing price on average in order to avoid missing a sale. They would earn less profit relative to other plants than under a uniform-price auction—just as hoped for by pay-as-bid advocates. Would that save consumers money? For a few years, it would, but no new baseload plant would be built until their profits returned to normal. This would only happen when a sufficient shortage of baseload plants had developed. That shortage would raise clearing prices in some hours when baseload is on or near the margin. This would just compensate for the 20% discount. As a consequence all plants would then be paid the same (their fixed plus variable costs), but the mix of plants would be inefficiently tilted away from baseload plants, because pay-as-bid would have discriminated against them. Consequently the average cost of producing electricity would increase. In other words, after a few years, even if pay-as-bid did work as hoped, consumers would still end up paying more.

Why energy prices are rising and what to do about it

We now return to the six factors responsible for rising electricity prices and provide some perspective. The first, and by far the largest factor, is simply the change in fuel costs, and in particular but not exclusively gas prices, over the last five years. This would increase electricity prices under any regime. The evidence that increases in fuel prices has been a major cause of increases in energy prices is compelling.

In PJM, the largest of the electricity markets, once we adjust for fuel cost, the spot energy price, which began at about $25/MWh, fell to about $20/MWh, and has remained there for the last six years, as shown below. However, the particular form of adjustment used in the graph assumes the law of one price and a complete lack of forward contracting. It demonstrates that some combination of market power reductions and efficiency gains have improved the market's performance, possibly in conjunction with some price suppression.[7] It also shows that, within a competitive spot market framework, fuel price increases are the entire cause of the price increase.

PJM Market Results 1998-2005
Comparison of Load Weighted Energy Prices to
Fuel-cost Adjusted Load Weighted Energy Prices



Note: Fuel-cost adjustment based on 1998 reference period and hourly marginal fuel type. All years are power years from April 1 to March 31, except 2005, which is through January 31. Source: PJM.

The second factor is the removal of retail rate caps. Some consumers have been temporarily protected from higher prices by retail rate caps. Naturally, when these caps are lifted, consumers experience rate shock. Even without such caps, consumers would have experienced a more gradual but more prolonged increase in prices. The only possible remedy for this problem is a shift from gas-fired generation to baseload generation, and, as described above, the market provides strong incentives for this shift.

The third factor is the shift to a disequilibrium in which, because baseload plants have a new-found advantage over gas-fired generation, they are in short supply. Being in short supply means they cannot set the price often enough, and instead, expensive gas plants set the price.

To investigate the impact of this factor, the graph above needs to be augmented with a comparison of wholesale energy prices and total fuel costs. This would allow an estimate of the extent to which disequilibrium in the stock of installed capacity has contributed to the windfall gains of baseload plants and the windfall losses of consumers. Such calculations would help focus attention on the need for better forward contracting.

The remedy for disequilibrium, as just noted, is more baseload capacity. This will take gas off the margin during some shoulder hours and lower the average price. When there are enough baseload units, they will no longer earn any windfall profits in the spot market.

An important question is whether there are barriers that will prevent the market from returning to equilibrium in this way. That is well beyond the scope of this paper, but it is important to note that the magnitude of the windfall consumer loss is closely tied to the size of such barriers. If the barriers are large, the problem could persist for many years; if they are low it might correct itself in only a few years. This report is not meant to suggest the barriers are large or difficult to remove; in fact they may be minimal or easily eliminated. The point is simply that to the extent they are allowed to exist, they will tend to cause windfall profits for existing baseload units.

The fourth factor, insufficient long-term forward contracting, is crucial. If complete long-term contracts were in place the disequilibrium problem would vanish. Unfortunately, forward contracting will not fix the problem after the fact. Once your house is on fire, fire insurance covering that fire is very expensive. California's experience with long-term contracts, during and after its electricity crisis beginning in 2000 is another vivid example.

An investigation of the extent of forward contracting would show that the consumers have not, in fact, experienced the entire cost increase implied by the spot price increases shown in the above graph. If an estimate of this effect could be made it would illustrate the benefits of forward contracting.

To protect against unexpected price increases, the forward contract must be signed while the increase is still unexpected. This does not mean it is too late to increase forward contract coverage. Rather it means that long-term forward contracts should be acquired by load in a way consistent with risk management and investment principles. Too often, load's contracting strategy appears to mimic that of the stock investor who looks only at past returns and buys yesterday's winners. The result is an outcome much worse than random purchase. Unfortunately, sound contracting by load has been frustrated by the absence of a well-defined representative of load to sign sensible long-term contracts. This is another basic problem that is beyond the scope of this paper.

Even if forward contracting is executed according to the best risk-management principles, it must be remembered that it will not, on average reduce expenditures—only the variance in those expenditures. The present disequilibrium does not represent a bias in the market. Had fuel costs shifted in the other direction the tables would have been turned. Similarly, forward contracting will increase consumer costs as often as it decreases them. Its benefit is to reduce risk—to counteract the spot market fluctuations by canceling both unexpected losses and unexpected gains.

The fifth factor is the law of one price. Under any market design, if the price of a MWh is high, a baseload plants will manage to get that high price, even if its costs are low. The law of one price plays a crucial role. It is not a law of nature, but it is a law that all competitive markets follow. As long as the market design remains competitive, there is little that can be done about this. Efforts to introduce price discrimination may succeed in the short-run, but in the long-run investment incentives are damaged and consumer costs are increased.

The sixth factor is the uniform-price design of the spot market. This is thought to be important when the law of one price is not recognized. Then it is often presumed that simply changing to pay-as-bid will up-end the law of one price. Fortunately, it will not. Suppliers that now bid zero, knowing the clearing price will be well above their marginal cost, will stop bidding zero if they are paid as bid. They will instead bid as close as they dare to the clearing price. While it is possible this will have a tiny depressing effect on the spot price, the result of lower prices will be that a few investments in new capacity will be discouraged (perhaps even before the pay-as-bid rule takes effect), supply will tighten, and the average spot price will be exactly where it would be under the uniform-price rule. Moreover, the uncertainty caused by forcing suppliers to bid based on their estimates of other's bids, instead of on the basis of their own costs, will reduce the efficiency of the dispatch. The net result will be to increase cost to consumers.

Conclusion

Three recommendations emerge from our analysis.

1. Do not switch from uniform-pricing to pay-as-bid pricing in the energy spot market. Hopes of saving money through price discrimination are naïve. Such a switch likely will increase consumer costs.
2. Do not attempt a regulatory taking of windfall profits and a regulatory allowing of windfall losses. Even if such a strategy achieved some short-run cost relief, it would destroy investment incentives, and thus, in the long-run, destroy the market.
3. Do look for sensible ways to encourage long-term forward contracts that hedge fuel-price shifts. Long-term contracts are the only market mechanism available to address the present concern.

Recommendations 1 and 2 are easy to implement. Recommendation 3 is much more difficult to follow. It requires solving one of the most important practical problems in electricity markets today. In today's markets, it remains unclear who should sign long-term forward contracts on behalf of residential and other small consumers. It is easy to say that contracts should be signed that are consistent with sound risk-management and investment strategy, but it is hard to implement when there is no counter-party to the contract. Residential and other small consumers are not represented properly in the current market design. This fact, not the design of the spot market, is at the heart of the current challenges in today's electricity markets.

One solution adopted in some states, such as New Jersey and more recently Illinois, is to require the electricity distribution companies to purchase long-term forward contracts from suppliers for residential and other small consumers. These contracts are procured in a sensible way via a competitive annual auction in which *n*-year contracts are purchased each year to cover a 1/*n* share of load. For example, New Jersey procures 3-year contracts covering $1/3^{rd}$ of load each year. Of course, consumers could enjoy even greater insurance from fuel-price shifts with contracts of even longer-term, procured on a more frequent basis, but there are credit and other issues that limit the optimal contract length.

[1] We would like to thank PJM Interconnection for funding. The views expressed are our own.

[2] We use the term uniform-price auction, since that is the term from the auction literature. In electricity circles, it is sometimes called a single-price auction, and in financial circles it is mistakenly called a Dutch auction. In two-sided markets, in which suppliers make offers and buyers make bids, it is sometimes called a double auction, or a uniform-price double auction.

[3] The revenue increase is only to the level needed for a peaker to break even, and although this is the required long-run level, there should be dip in ICAP revenues when there is competitive entry of new base-load units if those units are making windfall profits as assumed in Stage 2.

[4] See Cramton, Peter and Steven Stoft (2006), "The Convergence of Market Designs for Adequate Generating Capacity," white paper for the California Electricity Oversight Board, March.

[5] See Borenstein, Severin, James Bushnell and Frank Wolak (2002), "Measuring Market Inefficiencies in California's Wholesale Electricity Industry," *American Economic Review*, 92:5, 1376-1405 for empirical evidence in electricity markets; Gjerstad, Steven and John Dickhaut (1998), "Price Formation in Double Auctions," *Games and Economic Behavior*, 22, 1-29 for experimental evidence; and Gresik, Thomas A. (1991), "The Efficiency of Linear Equilibria of Sealed-Bid Double Auctions," *Journal of Economic Theory*, 53, 173-184, Satterthwaite, Mark, A and Steven R. Williams (1989), "The Rate of Covergence to Efficiency in the Buyer's Bid Double Auction as the Market Becomes Large," *Review of Economic Studies*, 56, 477-498, Satterthwaite, Mark A. and Steven R. Williams (1989), "Bilateral Trade with the Sealed Bid k-Double Auction: Existence and Efficiency," *Journal of Economic Theory*, 48, 107-133, and Wilson, Robert (1985), "Incentive Efficiency of Double Auctions," *Econometrica*, 53, 1101-1116, and Wilson, Robert (1993), "Design of Efficient Trading Procedures," in D. Friedman and J. Rust (eds) *The Double Auction Market*, Reading, MA: Addison-Wesley for theoretical support.

[6] See Kahn, Alfred E., Peter Cramton, Robert H. Porter, and Richard D. Tabors (2001), "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?" Blue Ribbon Panel Report, California Power Exchange; Kahn, Alfred E. , Peter Cramton, Robert H. Porter, and Richard D. Tabors (2001), "Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond," *Electricity Journal*, 70-79, July.

[7] For example, see Wolfram, Catherine D. (2005), "The Efficiency of Electricity Generation in the U.S. After Restructuring," in James Griffin and Steve Puller, eds., *Electricity Deregulation: Choices and Challenges*, University of Chicago Press, on efficiency gains.