Power System Economics

Designing Markets for Electricity

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Reliability, Price Spikes, and Investment

Chapter 2-1
Reliability and Investment Policy

When, by building theories upon theories, conclusions are derived which cease to be intelligible, it appears time to search into the foundations of the structure and to investigate how far the facts really warrant the conclusions.

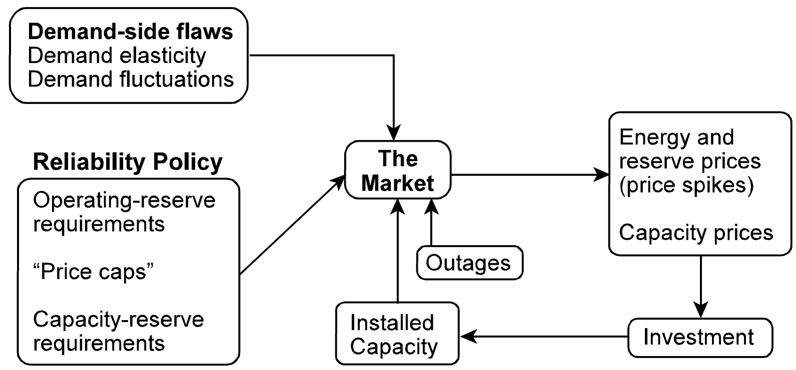
Charles Proteus Steinmetz
The Education of Electrical Engineers
1902

RELIABILITY, PRICE SPIKES, AND INVESTMENT ARE DETERMINED BY REGULATORY POLICIES. Because these policies impinge on market structure rather than architecture, they have been overlooked too often as debates focused on "nodal pricing," "bilateral trading," or on market rules. The result has been a chaotic pricing policy and disaster in the Western U.S. markets. Part 2 assumes away two major problems, market power and transmission constraints, to focus exclusively on the structural core of a contemporary power market. The goal of Part 2 is to explain the major policy options and their implications. This requires an understanding of the causal links between policy controls and the key market outcomes—reliability, price spikes and investment. Both controls and outcomes are diagrammed in Figure 2-1.1.

Supply and demand characteristics comprise a market's core structure, but in a power market these are unusually complex. The supply side cannot store its output so real-time production characteristics are important, and two demand-side flaws interact detrimentally with this characteristic. Consequently, the market cannot operate satisfactorily on its own. It requires a regulatory demand for a combination of real-time energy, operating reserves, and installed capacity, and this demand must be backed by a regulatory pricing policy. Without this reliability policy, the power system would under-invest in generation because of the demand-side flaws. Reliability policy is the part of the structural core that can be affected immediately by design. The demand-side flaws can also be affected by policy, but these design changes take longer to implement.

Without the demand-side flaws and reliability policy, Figure 2-1.1 would represent a normal market; demand and supply conditions would feed into the market and determine prices. These would determine new investment which would

Figure 2-1.1
The structural core of a power market determines reliability, price spikes, and investment.



determine the supply conditions and reliability. When the demand-side flaws have been sufficiently ameliorated, short-run reliability policy will no longer be required to play its current role of providing the major incentive for long-run investment in generating capacity. Price spikes will be controlled by demand elasticity and power markets will operate normally. Chapter 2-4 discusses the threshold at which this becomes possible.

Chapter Summary 2-1: Energy price spikes and, in some markets, installed-capacity prices induce the investment in generation which determines reliability. The duration of price spikes is roughly determined by accepted engineering rules of thumb, but no engineering and no market determines the height of the spikes. Their height is determined by often-murky regulatory policies that limit what a system operator will pay when the system runs short of operating reserve. Thus, neither determinant of investment, duration or height, is market driven.

Many regulatory policies would produce the right level of investment, but policies that employ extremely high, short-duration price spikes should be avoided because of their side effects. Such spikes cause investment risk, political risks, and increased market power. Correctly designed policies can ameliorate these and other side effects while inducing any desired level of investment.

Section 1: Why Price Regulation is Essential. The second demand-side flaw makes it possible for customers to avoid long-term contracts and purchase in real time from the system operator. Because the system operator sells at cost, its customers will never be charged more than the system operator's price limit. Consequently, they are not willing pay more in any market. If system operators had no policy of paying sufficiently high prices for enough hours per year, generators would not cover their fixed costs and would not invest. Thus, the market, on its own, would underinvest and reliability would suffer. System operators do have pricing policies, and these determine the height and duration of price spikes.

Section 2: The Profit Function. Regulatory policy determines the market's price when demand, including the regulated demand for operating reserves, exceeds total available capacity. These price spikes determine the short-run profits of generators, and the expectations of these profits induce generation investment. Investment increases **installed capacity** (ICap), which reduces both price and profits. This feedback loop (shown in Figure 2-1.1), which is controlled by reliability policy, determines the equilibrium level of ICap and thus long-run reliability.

The profit function summarizes the information needed to find the equilibrium ICap level. It takes policy into account and plots expected short-run profits (of **peakers**, for example) as a function of ICap. The equilibrium ICap level occurs at the point on the profit curve where short-run profits just cover the fixed costs of peakers. The short-run profit function derived from the combination of energy and capacity prices shows what level of ICap and reliability a given set of policies will produce.

Section 3: Side Effects of Reliability Policy. Many different policies produce the same optimal level of ICap and reliability, but they have different side effects according to the steepness of their profit functions. A steeper profit function increases risk and facilitates the exercise of market power. By choosing policies that produce low, long-duration price spikes, a flatter profit function can be achieved.

Section 4: Inter-System Competition. Competition between system operators militates against low price spikes. Any system operator with a low price limit on energy and reserves will find its operating reserves purchased out from under it at crucial times. Regional coordination of pricing policies can avoid such competition and its negative side effects.

Section 5: Demand-Side Effects of Price Limits. The ideal solution to the investment/reliability problem would be sufficient price elasticity to keep the market-clearing price well below the value of lost load at all times. A high price limit encourages demand elasticity, but this consideration must be weighed against the increased risk and market power associated with high limits. A better solution might be to price demand and supply separately during price spikes.

2-1.1 PRICE REGULATION IS ESSENTIAL

The second demand-side flaw, the system operator's inability to control the real-time flow of power to specific customers, necessitates the regulator's role in setting prices (see Section 1-1.5).[1] Without this flaw, the system operator could simply enforce contracts. Instead, it must buy power to balance the system and maintain reliability.

Although the system operator must play an active role in present systems, that role might be restricted to setting a price that equated supply and demand—in other words, a price that cleared the market. If this were possible, the system operator, though active in the price-determination process, would have no control over price and would not be a price regulator. In most hours of the year, the system operator does play such a passive role.

Because of the first demand-side flaw (a lack of real-time metering and billing) demand is so unresponsive to price that a simple market-clearing role is not possible in all hours. If installed capacity is at an optimal level or lower, there will be times during which demand exceeds supply and load must be shed. NERC estimates this will happen for about 1 day out of 10 years. At such times, no price will clear the market.

The system operator could continue to pay the highest nominal marginal cost (left-hand marginal cost) of any generator after the market failed to clear. This would still constitute regulatory price setting, but it would be a minor intervention. With only this minimal intervention, investment would suffer a serious decline. The competitive market-clearing price, when supply exceeds demand, is the physical marginal cost of generation which is usually less than \$200/MWh.[2] For this price to support investment in new peakers, demand would need to exceed supply (forcing blackouts) for more than 200 hours per year, not the 2.4 hours that NERC considers optimal.

Fallacy **[2-4.1]** **The "Market" Will Provide Adequate Reliability**

Contemporary markets, with their demand-side flaws and negligible demand elasticity, would grossly underinvest in generation without regulatory price setting.

The minimal price intervention that would produce a reasonable level of reliability is known as value-of-lost-load (VOLL) pricing. This has been studied

1. See also Ruff (1999, 28), and FERC (2001b, 4).

2. Some will object that for the last few percent of supply, marginal cost climbs rapidly to unlimited heights as wear-and-tear and the possibility of significant damage increases in the emergency operating range. This is correct, but it does not solve the present dilemma. These marginal costs cannot provide a benchmark for setting the market-clearing price when demand exceeds supply. They are not verifiable, and even if they were, just before the market fails to clear they easily exceed the value of power to consumers, VOLL. If price were set to the last marginal cost before failure, consumers would pay more than the power is worth and stimulate overinvestment in generation. Chapter 2-4 also discusses the possibility of using the high demand-sided bids, found in some more advanced markets, to set price. This is similarly inappropriate.

and implemented by Australia's National Electricity Market (NECA, 1999b). This approach recognizes that the system operator must purchase power on behalf of load when demand exceeds supply and instructs it to pay V_{LL}, the value of additional power to load, whenever some load has been shed (during a partial blackout). This is sensible, and ignoring risk and market power and given the first demand-side flaw, it produces an optimal outcome.[3] It induces exactly the right level of installed capacity, which minimizes the sum of the cost of that capacity and the cost of lost load.

Implementing VOLL pricing requires a regulatory determination of V_{LL} because the market cannot determine it. This value will determine the height of the aggregate price spike, and the duration of the price spike will be determined by the regulator's decision to set this price when, and only when, load has been shed.[4] The Australians estimated V_{LL} to be about \$16,000 US but set their price limit at only about \$10,000 US. Both the height and average annual duration of the price spikes under V_{LL} pricing are determined by regulatory policy and not by any market mechanism.

In the United States, system operators take a different approach. In compliance with NERC guidelines, they set operating reserve requirements which cover "regulation," spinning reserves and nonspinning reserves which together amount to roughly 10% of load. Instead of waiting until load must be shed to raise price, a shortage of operating reserves is deemed to be sufficient reason to pay whatever is necessary. This results in high prices whenever demand exceeds about 90% to total available supply, an occurrence far more common than load shedding. In this way, U.S. reliability policy determines a much longer duration for price spikes.

Determining the height of energy price spikes is more complex because system operators compete for reserves. If one operator is willing to pay a high price, it can buy up the reserves of its neighbor and thereby force it to pay a high price to acquire its own reserves. This complication is discussed in Section 2-1.4, but the essence of regulatory pricing is better understood by considering a single isolated market.

The engineering approach considers requirements for operating reserve to be sacred and avoids assigning a maximum price that should be paid to comply with them. The suggestion is to "pay what is necessary." Before markets, this caused no problems, but when prices exceed a few thousand

What's a Regulator to Do?

Prices must spike to pay the fixed costs of generators, or there will be no new investment. The highest price should occur when load has been shed, but even then the system operator should pay no more than the power is worth. Academics estimate this to be more than \$1000/MWh but less than \$100,000. The market gives no answer. Australian regulators pick a value near \$10,000 and thereby determine investment.

U.S. regulators, correctly wishing to reduce market volatility, choose a lower price limit and pay that price when reserves are low not just when load is shed. FERC's price limit and NERC's operating-reserve requirements combine to determine the long-run investment incentives—not by design but by chance.

When the demand-side is fully functional, elasticity-based price spikes will correctly determine investment. Spikes will be low and broad and the market stable. Present policy should seek to mimic this long-run, fully-functioning, competitive behavior. Policy should not deliberately mimic the volatility of a market with a demand-side that is still 98% frozen.

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3. The outcome is optimal provided VOLL is set correctly. Although this is extremely difficult to estimate, Section 2-5.4 shows that market efficiency is not too sensitive to misestimation and that there is no more accurate method available for determining the optimal amount of reliability.

4. The aggregate price spike is defined in Chapter 2-2, and is the upper part of the annual price-duration curve.

dollars per megawatt-hour, system operators understandably begin to have second thoughts.

As a result, all four ISOs have requested FERC's approval for "price caps." These are often, and more accurately, termed purchase-price caps. In fact they are simply limits on what the system operator will pay in order to comply with requirements for operating reserve. They are not price caps or price controls of the type implemented in other markets. They do not tell a private party that it cannot charge another private party more than P_{cap}. System operators are not allowed to make a profit, so they charge only as much as the power costs them, which is never more than their price limit. Because of the second demand-side flaw, when the system operator refrains from paying more than a certain price limit, no private party will pay more as it can always take power in real time without a contract.

The Price-Cap Result

Result [2-4.6] The Real-time Price Limit Effectively Caps the Entire Market

If a system operator never pays more than P_{cap} then it will never sell power for more. Because of the second demand-side flaw, customers of the system operator (typically, load serving entities) can always wait and purchase power in real time for P_{cap} or less. Consequently, they will never pay more in any forward market, and all power prices are, in effect, capped at P_{cap}.

Purchase-price limits, openly implemented by the system operator, typically determine the highest market price for the real-time market and for all forward markets, but it is not unusual for the system operator to make "out-of-market purchases" at prices above the official "price cap." These prices are not determined by the market because the demand for out-of-market purchases is typically caused by operating reserve requirements.

While there are sound engineering reasons for operating reserve requirements, these reasons do not extend to price determination. In particular, they do not say operating reserves are worth $2,000/MWh or any similar value whenever the reserve requirement is not met. Any price paid "out of market" is set by some regulatory, nonmarket process no matter how informal that may be.

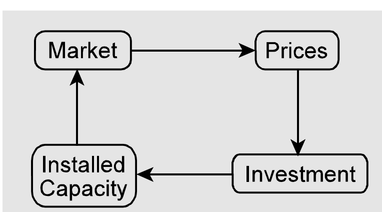
In conclusion, the limits on what a system operator will pay for power cannot be set by the market. They are set by complex processes that sometimes involve formal regulation and sometimes involve judgments by system operators. In any case, the high prices paid for reserves determine through arbitrage the prices in other markets (see Sections 1-8.3 and 2-4.5). Thus, system-operator policy determines the height of price spikes in all submarkets of a power market. Whether investment is induced purely by "market-driven" price spikes or by a "regulatory" ICap requirement, it is, in reality, primarily determined by a regulatory policy. Neither approach is more market-based than the other.

The Regulatory-Price-Spike Result

Result [2-4.4] Regulatory Policy Determines the Height and Duration of Price Spikes
Because of the second demand-side flaw, markets will not set energy prices higher than the system operator's price limit. Consequently this regulatory limit determines the height of price spikes. The average annual duration of spikes is controlled by the application of this limit to the operating reserve requirement.

The essential difference between the Australian and the United States approaches to the determination of price spikes is not that U.S. spikes are lower and of longer duration. The key difference is that Australia has determined the shape of its price spikes deliberately by calculating what is required to produce an installed-capacity level that will produce a target reliability level (some three to five hours per year of load shedding). The United States has made no such effort. In fact, price-spike *duration* is set by short-run engineering considerations, while the *height* of spikes is typically set by a political process that is concerned mostly with market power. Very roughly, NERC controls the price-spike duration, while FERC controls the height. But "NERC regional adequacy and operating reserve criteria do not consider costs" (Felder 2001) and FERC does not consider operating reserve limits when setting price caps. In addition, capacity requirements are often added to the market without any thought for how these mesh with the defacto price-spike policy. In short, Australia's approach is deliberate, while the U.S. approach is a matter of chance.

2-1.2 The Profit Function



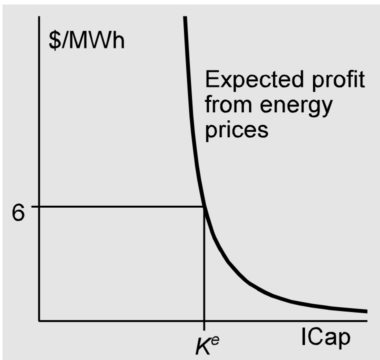
Profit drives the investment that is key to the market equilibrium de scribed by Figure 2-1.1. The core of that equilibrium process is the loop of causal links from the market through prices, investment, installed capacity and back to the market. This circularity determines a long-run market equilibrium.[5] If prices are high, investment will be encouraged, and installed capacity will increase.

With more ICap, prices will fall. The system is in equilibrium if ICap, combined with exogenous factors, causes prices that are just profitable enough to cover the fixed costs of the installed capacity.

Energy and capacity prices both contribute to profit and thus help determine the equilibrium level of ICap. Because separate policies affect energy and capacity prices, these must be coordinated if the right level of ICap is to be induced. The intermediate goal of these policies is to produce the right profit level at the right level of installed capacity, and the combined effect of energy and capacity prices on profit is what matters. This combined effect is computed by finding the profit function produced by each policy and summing the two functions.

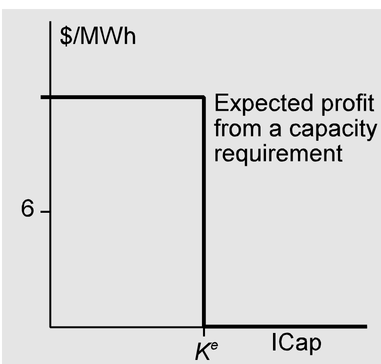
5. If prices are not capped and demand is too inelastic, there may be no equilibrium.

Result [2-8.1] Energy and Capacity Prices Together Induce Investment
Investment responds to expected short-run profits, which are determined by energy prices and (if there is an installed-capacity requirement) by capacity prices. Regulatory policies determining these prices need joint consideration.



A profit function plots expected profits as a function of the ICap level. A low ICap level produces shortages and high energy prices which provide a high profit level. When ICap is high, shortages are very infrequent and prices are rarely high. This leads to a low expected annual profit. At some level in between, expected prices are just high enough to produce a profit level that would cover the fixed cost of a new peaker, about $6/MWh of installed peaker capacity.[6] This is the equilibrium level of ICap, K^e.

The figure at the left shows a profit function for a peaker derived from energy prices. As ICap drops below the equilibrium level, profits increase rapidly, and as it rises above the equilibrium level, shortages of capacity become rare and profits rapidly fall to zero. In most markets they fall to zero much more quickly than shown. The precise shape of this curve depends on reliability policy, on the nature of demand fluctuations, the frequency of generation outages and on demand elasticity. The important points are that the curve depends on regulatory policy and the curve can be calculated.



An installed capacity requirement produces a very different profit function. When ICap is below the required level, ICap-profits for all generators are set by the ICap-requirement penalty, and when ICap is above the required level, profits are zero. (A small correction should be made for market power.) Adding profit from the energy market to profit from the capacity market produces a total profit function from which an equilibrium value of ICap can be determined.

The equilibrium value of ICap, K^e, is not automatically the optimal value. Policy must be adjusted so that the profit function of a peaker crosses the profit level (approximately $6/MWh) required to cover the fixed costs of a peaker at the optimal ICap level. Any profit function that does this, no matter what its shape, will induce the right level of ICap. Thus there are many "optimal" policies to choose from. Available policy parameters include the system operator's price limit when load is shed, the price limit when **operating reserve requirements** are not met, the required level of operating reserves (which can be increased), the required level of installed capacity, and the penalty for being short of capacity.

6. See Chapter 1-3 for an explanation of units. $/MWh can be converted to $/kW-year by multiplying by 8760 / 1000.

Result [2-6.1] Many Different Price Limits Can Induce Optimal Investment

If the system operator pays only up to P_{cap} but no more any time operating reserves are below the required level, a low value of P_{cap} will suffice to induce the optimal level of installed capacity. The higher the reserve requirement, the lower the optimal price limit will be. Capacity requirements can further reduce the optimal level of P_{cap}.

One other policy choice deserves attention. The engineering notion of an absolute reserve requirement, which worked well under regulation, makes little sense in a market. The demand for operating reserves, like the demand for anything else, should be described by a downward-sloping demand function. The fewer the megawatts of reserves, the more they are worth. Introducing such a demand function increases policy choices and has the added advantage of increasing the elasticity of demand in a market where even small increases matter.

2-1.3 SIDE EFFECTS OF RELIABILITY POLICY

Many policies will produce a profit function that determines the correct equilibrium level of installed capacity, but this does not mean they are all equally desirable. The first goal is the correct average level of installed capacity, but that is not the only criterion for a well-functioning power market. If ICap is right on average but fluctuates too dramatically, the excess *un*reliability in years of low ICap will more than offset the excess reliability in years of high ICap. In fact any value of ICap other than the optimal value causes a reduction in net benefit, so no matter what the average value, fluctuations produce a sub-optimal result.

But two phenomena other than reliability deserve attention—risk and market power. Even if the ICap were exactly right every year, so that reliability was optimally maintained, profits would fluctuate. The profit function only records expected, or average, profits. Actual profits can vary dramatically. A 2% increase in demand is equivalent to a 2% reduction in ICap in terms of its effect on profit. So if the profit function can be very steep at the equilibrium, any small unexpected increase in demand will cause a large increase in profits.

A VOLL pricing policy is designed to produce about three hours of extremely high prices (equal to V_{LL}) every year. But some years, unusual weather, generator outages, or unexpected demand growth will cause 10 or 20 hours of VOLL pricing. If ICap has been set correctly, then profits must average out correctly which implies there must be five years of zero profits for every year with 18 hours of high prices. Ten years of zero short-run profits—losses, from a business perspective—would not be out of the question. Investors will consider such a market very risky and will demand a risk premium for investing in it.[7] Moreover, because building power plants takes years, 2 high-profit years might well occur consecutively. In this case,

7. Long-term contracts between new generation and load can reduce this risk premium, but, so far, long-term contracting has meant only 2 or 3 years in most cases and the equilibrium level of contract cover is still unknown.

there may be political repercussions from the observation of high profits coupled with the pain of high prices.

A profit function that is extremely steep also encourages the exercise of market power. Withholding 2% has the same impact on profits as a 2% reduction in ICap. So profit functions that are very steep reward withholding most handsomely. Again, the VOLL pricing policy fits this description.

A flatter (less steep) profit function can be obtained by designing price spikes that are lower and of longer duration. Instead of $15,000/MWh for 4 hours per year, one can design price spikes that reach only $500/MWh for 120 hours per year. This would be done by setting a purchase price limit for the system operator of $500 and requiring that it be paid whenever the system was short of operating reserves (instead of waiting until an actual blackout). If this still does not produce high prices for 120 hours per year, the operating reserve requirement could be increased.

In addition, part of the fixed costs can be recovered from the capacity market if the correct capacity requirement and the penalty are implemented. If half the fixed cost is recovered in the capacity market, the height of price spikes can be cut in half for any given duration of high prices. Some policy combinations produce flatter profit functions and these reduce risk and the exercise of market power. If properly designed, these policies will cause no reduction in the equilibrium level of installed capacity. Consequently, it is the side effects of reliability policy, risk and market power, which should determine the structure of the policy and thus the shape of the profit function.

Result [2-6.4] Reliability Policy Should Consider Risk and Market Power

The right average installed capacity will provide adequate reliability, but two side effects of reliability policy should also be considered. Infrequent high price spikes increase uncertainty and risk for investors. This raises the cost of capital and, in extreme cases, causes political repercussions. The possibility of extremely high prices also facilitates the exercise of market power.

2-1.4 INTER-SYSTEM COMPETITION

Consider an isolated competitive market in which $200/MWh is sufficient to call forth all available operating reserves. Suppose $500/MWh is sufficient to purchase all power available from these sources during an emergency. As these prices are too low to stimulate the appropriate level of investment given most operating reserve policies, the system operator has imposed an ICap requirement and enforced it with a moderate penalty. This provides capacity owners with an additional source of profits, which is just sufficient to induce optimal investment.

This policy provides a relatively smooth profit function which reduces risk for investors and discourages the exercise of market power. While engineers may consider $200/MWh an inadequate effort to “buy reserves at any cost,” the fact remains that a higher price would procure no more in the short run. Even a supplier with market power would not withhold reserves in the face of a firm price limit, because there would be no possibility of profiting from a price increase. In the short run, paying more would not increase reliability, and, in the long run, it would only serve to increase it above the optimal level.

If this isolated market were connected to another, identical, market, these conclusions would change. Now both markets will find that they can increase short-run reliability by paying more for operating reserves. When reserves are short, say only 5% instead of the required 10%, either system can obtain a full complement of operating reserves by outbidding the other.

To be specific, assume each market has 10,000 MW of load and 10,500 MW of capacity, but system A has purchased 500 MW of operating reserves from system B as well as 500 MW of reserves from its own suppliers. System B now has zero operating reserves while system A has its required 10%. Suppose a generator selling 500 MW of power to market B experienced a **forced outage**. Market B will then be forced to shed 500 MW of load. A similar outage in Market A would cause only a reduction of operating reserves from 1000 to 500 MW.[8]

By bidding above market B's price limit and purchasing its reserves, market A has increased its reliability, something that was impossible when the two markets were isolated and not in competition. Of course, market B will soon realize what has happened and retaliate by bidding above A's price limit. The end result of such competition will be high limits on the price of operating reserves and energy. This will make the profit functions steep and will increase risk and facilitate the exercise of market power. This outcome was acknowledged by FERC in its July 2000 ruling approving identical price caps of $1,000 for the three Eastern ISOs. It correctly ruled against a $10,000 price cap for the NY ISO on the grounds that this would tend to undermine PJM's $1,000 price cap.

Result [2-9.1] Competition Between System Operators Induces High Price Spikes

If two markets with different price spike policies trade energy and operating reserves, the one with higher price spikes will gain in reliability and save money relative to the other. This will force the low-spike market to use higher price spikes. If regional price limits are not imposed, inter-system competition will lead to reliability policies with undesirable side effects.

2-1.5 DEMAND-SIDE EFFECTS OF PRICE LIMITS

Low, long-duration price spikes can induce the same optimal level of installed capacity as high narrow price spikes, but the side effects of risk and market power will be reduced. Besides these supply-side effects which argue against high price spikes, there is a demand-side effect that argues for high price spikes. High prices encourage price responsiveness both directly and through learning. Some loads

8. It may be suggested that under some emergency agreement system A would allow system B to purchase power from system A, thereby avoiding load shedding by B and reducing A's reserves below its required level. But this implies that A's reserves are in effect also B's reserves. In this case, there is no reason for either to spend extra on reserves as long as it knows the other will purchase them and share them. This contradicts observed behavior of system operators who do pay extra to obtain their own reserves.

will not find it worth curtailing their use of power until prices exceed $1,000/MWh. But, once a load has learned to respond, it may find it sensible to respond to price increases that would not trigger a response before the necessary control equipment is installed and such responses become routine.

Although these effects are important, they do not negate the conclusions based on the supply-side effects, though they suggest a trade-off. The demand-side response obtained by utilizing extremely high price spikes with no warning time may be little more (or even less) than the demand response obtained by lower, more frequent price spikes. These may be more readily anticipated by day-ahead markets, thereby giving loads a day's lead time to plan their response and implement cost-mitigating procedures.

Another possibility is to set demand-side prices higher than supply prices during price spikes. This would require a balancing account to keep the two revenue streams equal in the long-run, but that is a simple matter.

A similar problem arises from the possibly high prices required to wring the last MW of production out of generators. The price of power supplied by generators operating in their emergency operating range could be exempted from the normal energy price limit. Suppose the normal energy price limit were $500/MWh, and the maximum output at this price from generator G were 400 MW over the previous year. Then any output above 400 MW could be subject to a price limit of $2,000/MWh, without significantly steepening the profit curve.

Once the ideas of calculating profit curves and considering the side effects of their shape have been understood, many design possibilities can be considered and evaluated. In the long run, when demand has become quite elastic even in the extremely short timeframes needed to replace spinning reserves, these design considerations will no longer be needed. Before that time, much can be gained by taking full advantage of the multitude of policies compatible with an optimal average level of installed capacity. A pricing policy should be selected from among these based on its ability to minimize the collateral damage from risk and market power.