THE FINANCIAL AND PHYSICAL INSURANCE BENEFITS OF PRICE-RESPONSIVE DEMAND

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1. INTRODUCTION

Most energy analysts, industry decision makers, and government policy makers recognize the economic, reliability, and environmental benefits of integrating retail and wholesale electricity markets.[1] A key feature of this integration is the opportunity for customers to participate in wholesale markets by facing dynamic prices that vary from hour to hour.

Encouraging at least some customers to see and respond to time-varying electricity prices is essential to competitive markets because electricity costs vary dramatically from hour to hour, between weekdays and weekends, and by season. Customers that see these prices and that respond (by reducing demand when prices are high and by increasing demand when prices are low) benefit all customers, not just themselves. As discussed below, this broader benefit is a consequence of the fact that reduced consumption when prices are high leads to lower prices.

The high variability of spot-market electricity prices illustrates an important, but often overlooked, feature of retail electricity markets: the traditional time-invariant price paid for electricity includes two components.[2] The first is the electricity commodity, the kilowatt-hours of electricity we consume whenever we want to in whatever quantities we choose. The second is an insurance policy (risk premium) that protects customers from the volatility of electricity prices by permitting them to buy unlimited quantities of electricity at a fixed price that is determined months (or even years) before consumption.[3] Most consumers, industry decision makers, and government regulators do not yet recognize the existence and importance of this second component—the risk premium—associated with fixed electricity pricing.

Puget Sound Energy, an exception to the previous statement, proposes to offer its retail customers two choices in rates.[4] The first choice would adjust rates on a daily basis to reflect the volatility of wholesale power costs the utility experiences. The second rate option would include the company's costs of hedging rates against this volatility and would be adjusted only annually. The company's initial estimate of those hedging costs it could readily quantify is almost $3/MWh, between 5 and 10% of total generation costs. This estimate includes the costs of hedging against uncertain hydroelectric output, forced outages at thermal resources, and unusual temperatures (which affect electricity use for space heating).

This paper explains this insurance aspect of electricity pricing and demonstrates its value with simulations of the benefits of dynamic pricing when electricity costs and price are increasingly volatile. The paper also draws analogies between other risks (car insurance and financial investments) and the electricity industry.

Traditionally, retail customers paid for the costs associated with these risks—but not in real time. Utilities managed risk by building "extra" generating capacity. This planning reserve margin was intended to ensure the utility's ability to meet almost any foreseeable load. The capital and operating costs associated with this extra capacity were typically recovered from customers in rates that remained constant throughout the year. This approach is an economically inefficient way to manage risk because it assumes that all customers value electricity the same and have almost no ability to shift usage from on- to off-peak hours. In addition, wholesale prices were based on regulated costs and, therefore, showed much less volatility than those that occur in today's competitive markets.

Utilities collected any approved changes in power-supply costs (e.g., caused by changes in fuel costs) relative to those in base rates through monthly or quarterly fuel-adjustment clauses. If costs were consistently higher, the utility would seek a rate increase from the public utility commission. Alternatively, if costs were consistently lower, the commission would require the utility to file a new rate case in an effort to lower rates. These delays in adjusting consumer prices to reflect costs, coupled with the absence of hourly meters, prevented customers from being able to respond to the time-varying costs of electricity.

Retail suppliers that offer electricity at a fixed price accept both quantity and price risks. The price risk reflects the a priori unknown level and volatility of electricity prices. The quantity risk reflects the likelihood that electricity consumption will be higher when prices are higher. Electricity consumption and prices are highly correlated, as one would expect. Consider the PJM Interconnection, a 55,000-MW system, as an example. For the week shown in Fig. 1, the correlation between prices and quantities shows that the amount of electricity consumed explained 72% of the variation in electricity prices. (Other factors, such as sudden generator or transmission outages, can also yield high prices.)

For example, a customer with a time-invariant load willing to face spot prices would pay $47/MWh on average for the week shown in Fig. 1. If, however, the customer consumed electricity using the same load shape as the PJM system, its consumption-weighted price for the week would be $54/MWh, 15% higher than the unweighted average price. To cover its risk-management costs, a supplier selling fixed-price electricity would have to charge more than the average price to make a reasonable profit. Altogether, it might offer customers a fixed price of, say, $60/MWh for this period to account for price and quantity risks.

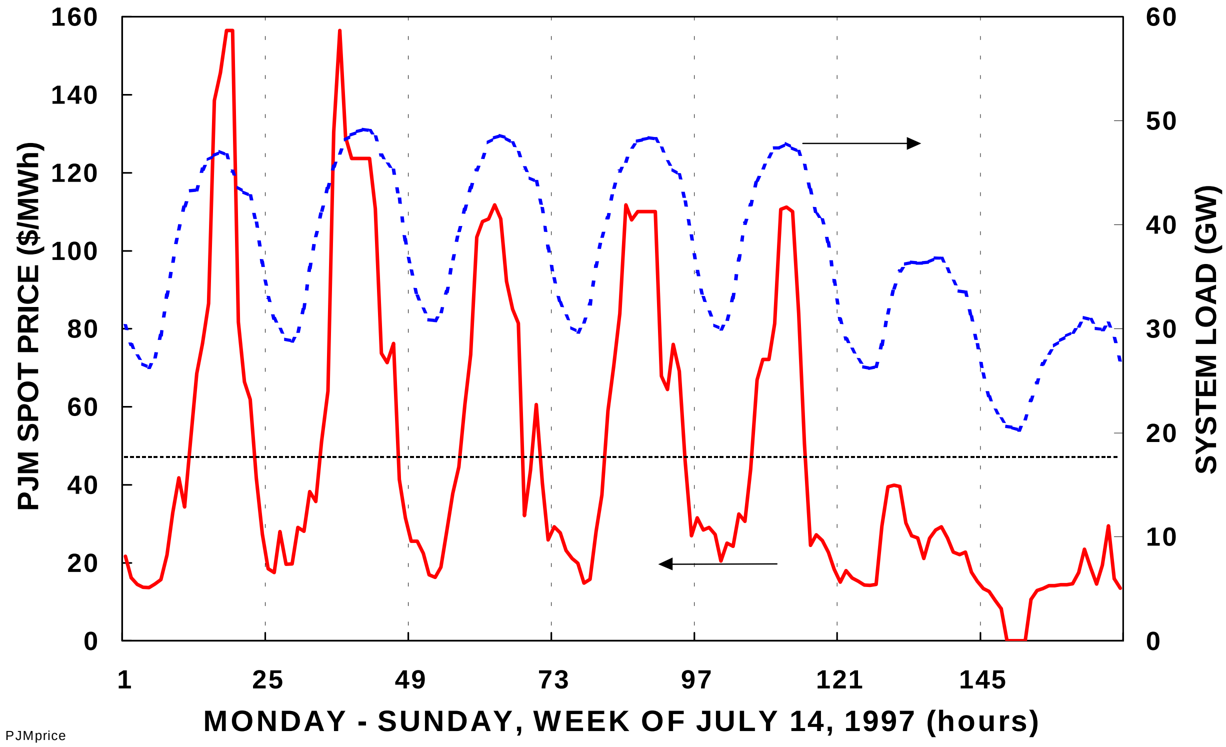


Fig. 1. **Hourly prices and system load in the PJM Interconnection for one week. Prices ranged from $0 to $157, with an average of $47/MWh and a standard deviation of $38/MWh. Load ranged from 20 to 49 GW, with an average of 37 GW and a standard deviation of 8 GW.**

On the other hand, customers that choose dynamic pricing would pay less for electricity over the long run. These customers would do so by buying only the electricity commodity and by accepting the risks of price volatility (i.e., providing the insurance themselves). In addition, such customers can modify their loads in response to those prices and further lower their electricity costs. Thus, these customers provide themselves with both financial and physical forms of insurance. Finally, the load reductions at times of high power prices lower overall prices and, thereby, benefit *all* electricity consumers.

2. SIMULATION RESULTS

When customers choose electricity prices that vary temporally (from hour to hour, from one block of hours to another, from day to day, and from season to season), they receive important economic signals. These signals, if they are delivered to customers in a timely fashion, let them know when it is cheap to produce electricity (and they might want to use more) and when it is expensive (and they might want to use less). Any changes in the timing of electricity use associated with these temporal price signals lower electricity costs to those customers. In addition, these load-shape changes reduce the frequency and magnitude of wholesale-power price spikes, leading to additional economic benefits enjoyed by all electricity consumers, not just those with dynamic prices.

To simulate the benefits of price-responsive demand, I obtained hourly data from the (former) California Power Exchange (PX) on day-ahead electricity prices and scheduled loads.[5] I ran simulations for 1999 (a normal year) and 2000 (when the California electricity markets exploded).

I converted the PX *wholesale* prices into *retail* prices by adding an assumed cost for transmission, distribution, and customer service of $40/MWh. I assumed that 20% of retail load faces time-varying prices and that customers, on average, adjust their consumption in response to price changes with a price elasticity of demand of −0.25, yielding an overall elasticity of −0.05 for customer response to hourly price changes.[6] I next calculated the change in retail load for every hour of the year, based on the original PX loads and prices and the assumed elasticity value.

I then used an assumed power-supply curve to calculate the change in wholesale electricity price caused by the change in retail demand discussed above (Fig. 2). This curve is based roughly on the bids submitted to the California PX; results for the New York and PJM markets show very similar curves. Figure 2 shows that the price of electricity increases only modestly as demand increases when regional supplies are ample relative to demand. However, when supplies are tight (at the right side of the graph) small increases in demand lead to very large increases in electricity prices.

The net result of these calculations is two sets of hourly loads and prices, one without dynamic pricing (i.e., assuming all customers faced a time-invariant, fixed price for electricity) and one with dynamic pricing. Finally, I calculated annual electricity costs for retail customers with and without customer response to changes in hourly electricity prices. To simplify comparisons of results, I set annual electricity consumption in both cases equal. That is, I ignored any conservation benefit of dynamic pricing in this analysis.

The California PX load averaged 22,000 MW during 1999. Its day-ahead price averaged $28.3/MWh (with a standard deviation of $15.7/MWh), and the total cost of wholesale energy was $5.82 billion. The correlation between hourly loads and hourly prices was substantial, with a correlation coefficient of 0.64. Assuming that the market in which California electricity producers and consumers exist encompasses 150,000 MW,[7] and that the price elasticity of demand for electricity is −0.05, implementation of dynamic pricing would have cut the state's electricity bill by almost 4%, equivalent to an annual savings of $220 million. About 14% of this savings occurs because of changes in electricity use caused by dynamic prices, with the remaining 86% associated with the demand-induced changes in wholesale electricity prices.[8]

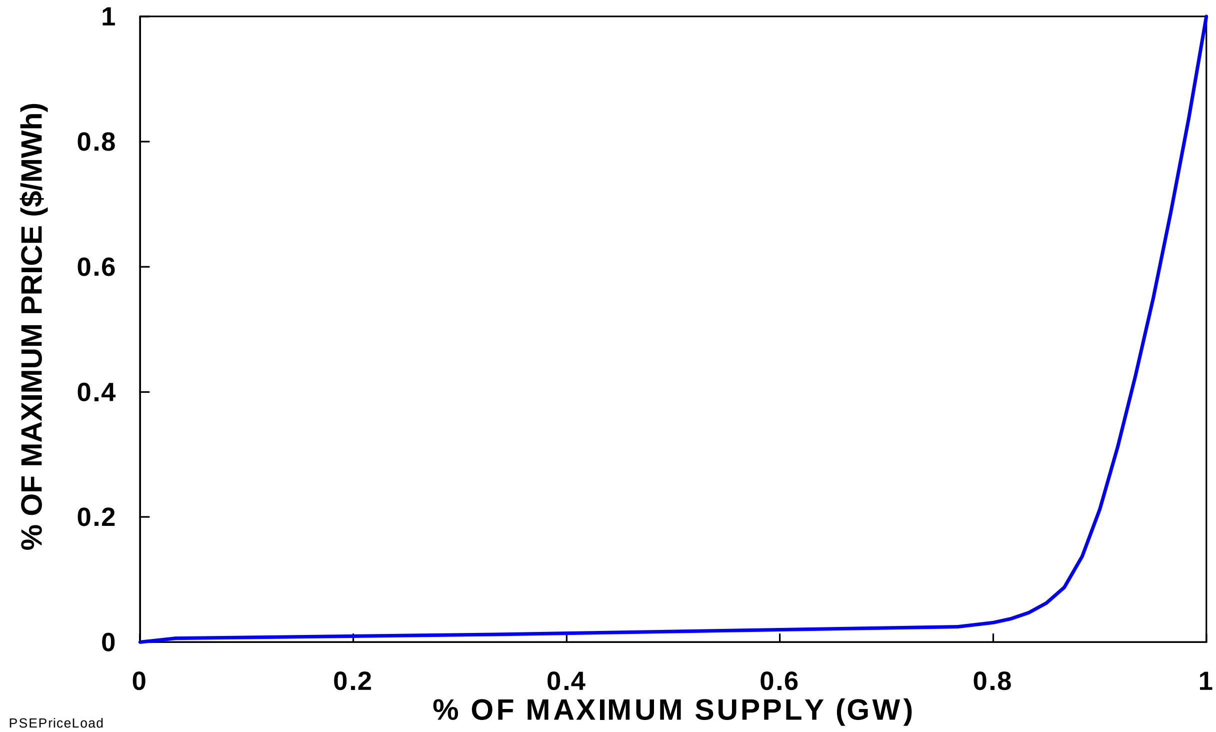


Fig. 2. **Assumed power-supply curve showing the relationship between the wholesale price of electricity and the supply of electricity. Small changes in load have much larger effects on price when price is high (right side of graph) than when prices are low (left side).**

In 2000, the California PX load was slightly lower than in 1999 (21,400 vs 22,000 MW). But prices were, on average, almost four times higher, $111/MWh. Not surprisingly, prices in 2000 were also much more volatile than they had been the year before; the standard deviation of hourly prices in 2000 was $139/MWh. The correlation coefficient between hourly loads and wholesale prices was much less than in 1999, 0.18 vs 0.64. Clearly, factors other than load were affecting electricity prices in 2000.[9] Using the same assumptions given above, dynamic pricing would have cut the state's power bill by almost 12%, equivalent to a savings of $2.5 billion.[10] In this case, price-induced consumption changes account for 31% of the total savings and consumption-induced price changes account for the other 69%.

Comparing the results for 1999 with those for 2000 shows that the higher prices and greater volatility in 2000 increased the benefits of price-responsive demand by more than a factor of ten. This dramatic difference in results demonstrates the insurance value of price-responsive demand programs. During "normal" years, such programs may provide only modest benefits. But when serious problems occur in wholesale electricity markets, these programs can provide enormous benefits.

To explore this concept further, I conducted additional simulations with the California data for 1999. Specifically, I examined the benefits of price-responsive demand as the volatility of wholesale electricity prices increased and as the overall level of prices increased. As shown in Table 1 and Fig. 3, the benefits increase quite dramatically as the volatility of prices increases. Dynamic pricing provides no benefits when price volatility is zero because prices are the same every hour. The benefits of dynamic pricing increase rapidly with price volatility. For example, raising the volatility by 25% from its 1999 value increases the power-supply savings by 34%, raising the volatility by 50% increases the savings by 72%, and doubling the volatility increases the savings by 160%. By comparison, increases in the overall level of prices have less effect on the benefits.

Table 1. Percentage reduction in annual electricity costs for California in 1999 as a function of price volatility and average level

Average price	Standard deviation of hourly prices ($/MWh)				
($/MWh)	15.7	18.5	24.7	32.4	40.7
28.3	3.8[a]	4.7	7	10.6	15.5
38.3	5.9	6.9	9.4	13.3	18.9
48.3	8.6	9.3	11.8	15.8	21.8

[a]This is the estimated savings for the conditions that actually occurred that year.

The benefits increase dramatically as price volatility increases because there are more hours with either very high or very low prices. Across the range of cases considered here, the fraction of hours with wholesale prices greater than $50/MWh increases from almost 6% with the original data to almost 25% when the standard deviation is almost tripled. The fraction of hours with prices greater than $100/Wh increases from less than 1% to almost 4%. When prices are very high, consumers reduce demand, which in turn lowers prices. When prices are very low, consumers increase demand, which increases prices. However, the effects on prices are much greater when prices are high than when they are low, as shown in Fig. 2.

The load changes caused by dynamic pricing account for 14 to 26% of total cost reductions across these cases. In other words, roughly 80% of the consumer benefit is associated with reductions in wholesale prices caused by reductions in peak demand. Because this benefit (a wealth transfer from generators to consumers) is enjoyed by all customers, it could lead to a free-rider problem. Will customers decline to participate in dynamic-pricing programs in the hope that enough other customers will do so to materially lower wholesale spot prices?

3. OTHER INDUSTRIES WITH COMPARABLE RISK ATTRIBUTES

We have seen that customers paying for electricity under traditional tariffs are implicitly paying the local utility for insurance as well as for the electricity commodity. Those customers

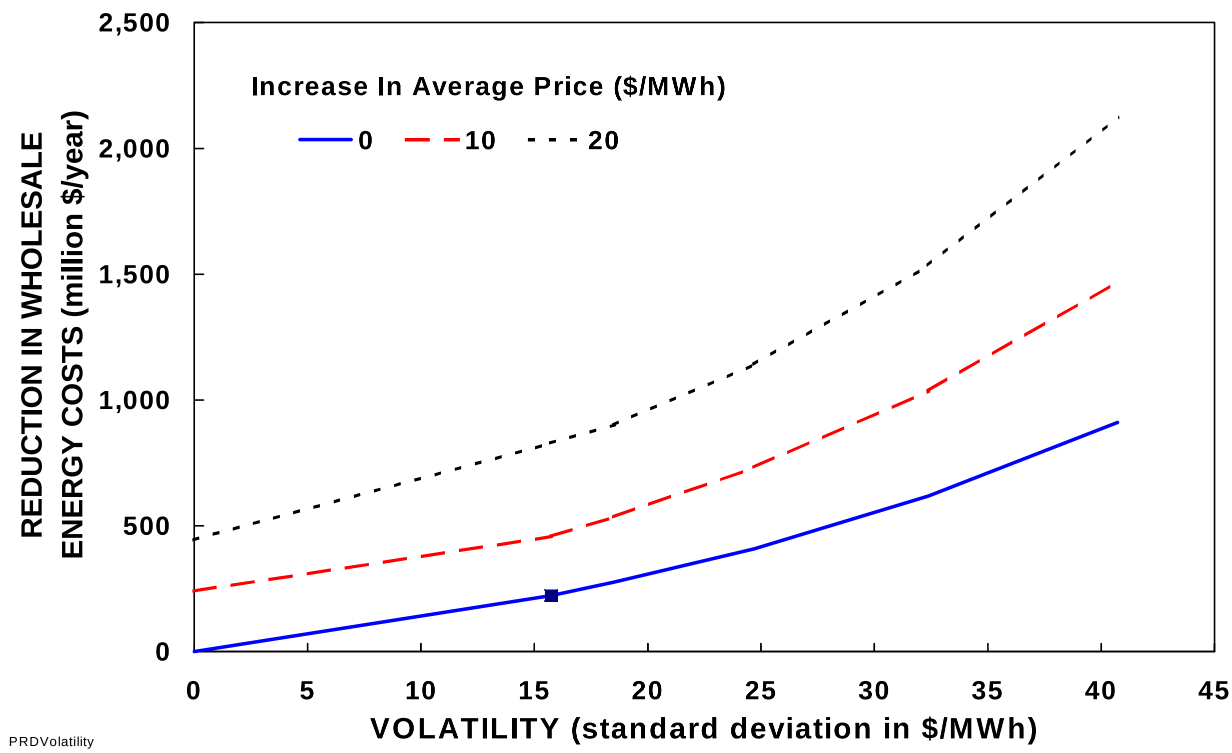


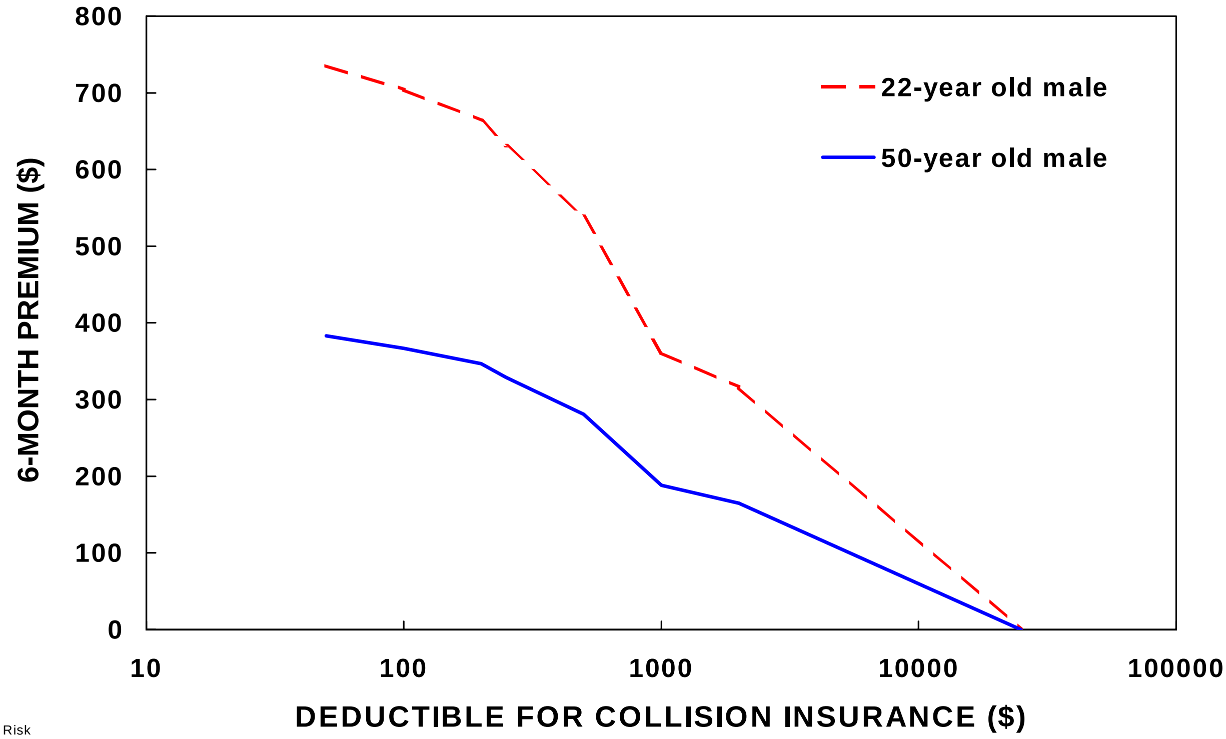
Fig. 3. Reduction in wholesale California electricitycosts in 1999 as a function of the overall level and volatility of electricity prices. The marked point represents the actual 1999 prices.

with interval meters that choose to face dynamic prices provide their own financial insurance. In addition, by modifying their electricity use in response to price changes, these customers provide a form of physical insurance that benefits all customers.[11]

Although the financial insurance aspects of electricity are new and unfamiliar to most consumers and regulators, consumers have ample experience with the underlying concepts. Consider automobile insurance as an example. Individuals have a range of risk-management options to consider when deciding how much insurance to purchase. Figure 4 shows the premium for collision insurance on a new Ford Taurus located in Anderson County, Tennessee. If the car is driven by a middle-aged man who wants maximum protection, the premium is $383

for a $50 deductible. In the event of an accident, the holder of this insurance policy will have to pay no more than $50 for repair to the vehicle. At the other end of the spectrum, the owner could self insure by declining to buy any collision insurance, thereby saving the $383 premium. In the event of an accident, however, this owner will have to pay for the entire repair bill (up to the full value of the car if it is totaled).

If the owner of this car was a 22-year old male instead of a 50-year old male, the insurance premiums would be roughly double. This higher premiums reflect the much higher probability that young men will get into automobile accidents.



Risk

Fig. 4. Collision-insurance premiums for a new Ford Taurus located in Anderson County, Tennessee, as a function of the deductible amount. (Note that the horizontal axis is logarithmic.)

This example illustrates two points relevant to electricity markets. First, consumers have experience in dealing with tradeoffs that involve risks and costs. Historically, regulatory commissions and electric utilities made this tradeoff on behalf of all customers, thereby denying customers an important opportunity to decide for themselves how much they are willing to spend to protect themselves against volatility in electricity prices.

Second, risk profiles differ among customers. Just as the young male poses more risks than older drivers, electricity customers differ in how they use electricity and want to manage the price and quantity risks associated with time-varying price. Some customers will likely pay a power supplier to manage those risks on their behalf; they will want to continue to pay for electricity under the traditional fixed-price, all-you-can-eat tariff. Other customers, however, may be more price sensitive and therefore willing to manage these risks for themselves. In return for a lower price (analogous to a lower collision-insurance premium), they face more risk (analogous to a higher deductible amount).

Financial markets have the same characteristics discussed above. In general, the more risk an investor is willing to accept, the more likely she is to earn a higher return. At one end of the spectrum an investor can buy certificates of deposit, for which both the interest and principal are guaranteed. In return for this very high level of security, the return on this

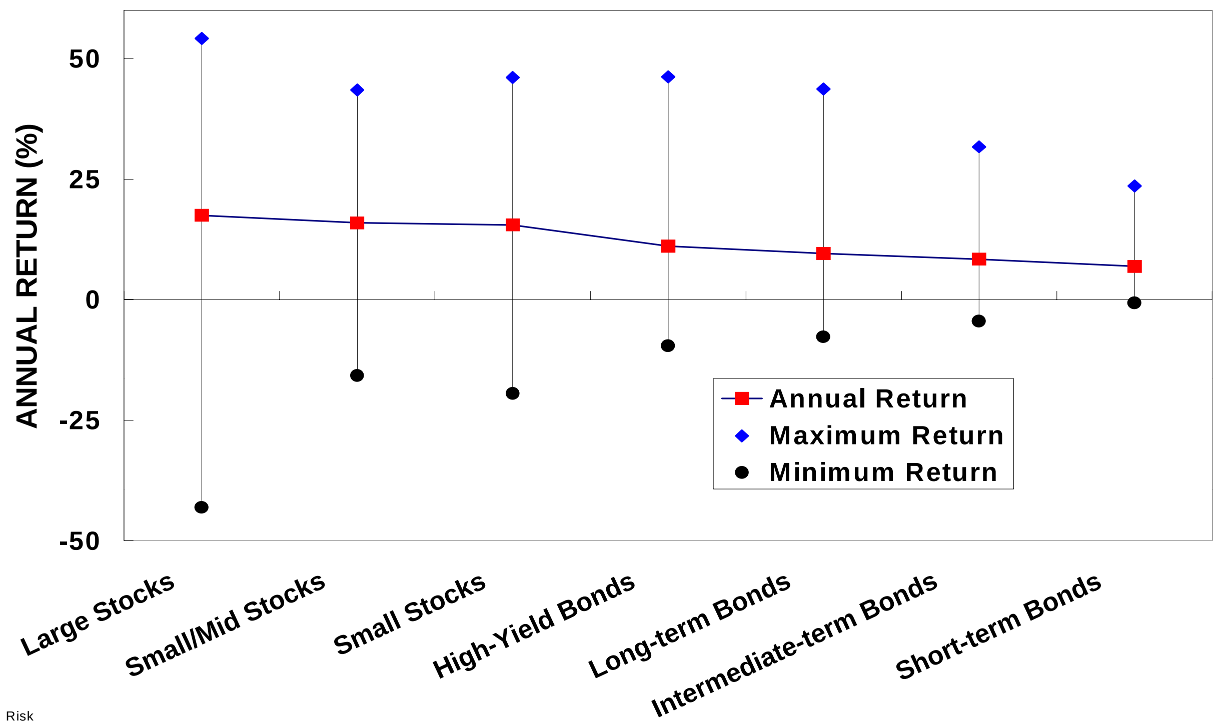


Fig. 5. **Historical (1991–2000) performance of selected financial-market segments, showing the average annual return and the maximum and minimum annual gains and losses.**

investment is very low. At the other end of the spectrum, one can buy stock in small, startup companies. Although the risks of failure are large (leading to the complete loss of one's investment), so too are the potential gains.

Figure 5 shows the performance of several types of stocks and bonds from 1991 through 2000.[12] The chart shows the average return for the decade for seven broad classes of investment. The chart also shows the range of annual returns (i.e., the difference between the maximum and minimum 1-year returns). As one moves from left to right across the graph, the average annual return declines and so does the risk.

The risk:return tradeoff shown in Fig. 5 is analogous to that associated with various pricing strategies an electricity provider can offer its retail customers. Those seeking security can choose a fixed-price tariff that includes an insurance payment (analogous to short-term bonds or certificates of deposit). At the other end of the spectrum, those customers willing to face the risks of wholesale power markets can choose a rate that offers dynamic prices that vary with wholesale-market conditions. In return for accepting a higher level of risk, such customers can lower their electricity costs, both by managing their electricity use in response to temporal changes in prices and by accepting the risk-management function. This is analogous to investors who, seeking higher returns, accept the higher risks of buying stocks rather than bonds.

4. CONCLUSIONS

Achieving the goals of the 1992 Energy Policy Act and subsequent orders from the Federal Energy Regulatory Commission requires that some retail customers participate in wholesale markets. Permitting and encouraging retail customers to respond to dynamic prices will improve economic efficiency, discipline wholesale-market power, improve reliability, and reduce the need to build new generation and transmission facilities.

Implementing such price-responsive demand programs requires policy makers to understand and accept the insurance aspects of dynamic pricing. During "normal" years, these programs might save only modest amounts of money. However, during those infrequent times when a combination of adverse circumstances occur (such as high fuel prices, insufficient generation capacity, and rapid load growth), the payoff from this insurance more than justifies the modest premiums paid during normal years. Like other forms of insurance, the benefits are greatest when you most need them.

Traditional, time-invariant electricity rates implicitly include financial insurance. Such insurance protects consumers against risks associated with temporal changes in wholesale electricity prices and the strong positive correlation between consumption and prices. Such insurance is not free!

Customers can self-insure in two ways. First, they can choose to face time-varying prices and avoid paying for the financial insurance discussed in the paragraph above. Second, and probably more important, such customers can provide physical insurance by responding to temporal price changes. Because of the strong nonlinearities in wholesale-power supply curves (Fig. 2), customers that cut consumption when prices are high lower wholesale electricity costs for all customers.

State regulators should permit customers to decide for themselves whether and how much risk they want to manage on their own or whether they want to pay others to manage those risks. Those that manage their own risks benefit by eliminating the payments for financial insurance and provide physical insurance by managing their electricity consumption in response to time-varying electricity prices.[13]

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2000; Congressional Budget Office, *Causes and Lessons of the California Electricity Crisis*, U.S. Congress, Washington, DC, September 2001..

2. E. Hirst and B. Kirby, *Retail-Load Participation in Competitive Wholesale Electricity Markets*, Edison Electric Institute, Washington, DC, and Project for Sustainable FERC Energy Policy, Alexandria, VA, January 2001.

3. These two components apply only to the energy portion of the electricity price and not to the transmission, distribution, and customer-service components.

4. W. A. Gaines, *Direct Testimony of William A. Gaines on Behalf of Puget Sound Energy*, Docket No. UE-011570, submitted to the Washington Utilities and Transportation Commission, Puget Sound Energy, Bellevue, WA, November 26, 2001.

5. I used day-ahead, rather than real-time prices, because most customers require some advance notice of price changes in order to modify their processes and energy-use behaviors.

6. There are many ways to arrive at an assumed overall elasticity value by varying the fraction of customers that choose dynamic pricing and the elasticity of demand for those customers. The elasticity value used here is roughly consistent with the literature; see Christensen Associates, *Electricity Customer Price Responsiveness—Literature Review of Customer Demand Modeling and Price Elasticities*, prepared for the California Energy Commission, Sacramento, CA, September 29, 2000.

7. Although the California system is on the order of 50,000 MW, the Western Interconnection is about 150,000 MW. The larger the assumed size of the region, the smaller the effect of load changes on wholesale prices.

8. A recent analysis estimated that 20% of the cost reduction associated with national implementation of dynamic pricing would come from individuals reducing their consumption during peaks, with the remaining 80% caused by the lower wholesale peak prices that result from reductions in peak demand. See McKinsey & Company, *White Paper: The Benefits of Demand-Side Management and Dynamic Pricing Programs*, May 1, 2001. Analysis of the demand-response programs in the PJM Interconnection during summer 2001 showed that these programs reduced wholesale spot prices by an average of $135/MWh; see PJM Interconnection LLC, *Report on the 2001–2002 PJM Customer Load Reduction Pilot Program*, Norristown, PA, submitted to the Federal Energy Regulatory Commission, Docket No. ER01-1671-000, December 28, 2001.

9. E. Hirst, *The California Electricity Crisis: Lessons for Other States*, Edison Electric Institute, Washington, DC, July 2001.

10. Braithwait and Faruqui estimated that customer demand response to hourly, market-based retail prices could have cut power costs by 5 to 16 percent for the months of May through August 2000. See S. Braithwait and A. Faruqui, "The Choice Not to Buy: Energy $avings and Policy Alternatives for Demand Response," *Public Utilities Fortnightly* **139**(6), 48–60, March 15, 2001.

11. Consumers can purchase fire insurance to help pay for any losses that occur if their house catches fire. In addition, consumers can provide physical insurance by installing smoke detectors and sprinklers in their houses.

12. The Vanguard Group, *Measuring Mutual Fund Performance*, Valley Forge, PA, 2001.

13. I thank Steven Braithwait, Kenton Corum, Richard Cowart, William Eastlake, Charles Goldman, Meghan Jonee-Guinn, Brendan Kirby, David Meyer, and Gary Swofford for their very helpful comments on a draft of this paper.