Restructuring and Stranded Costs: Theory, Practice, and Unforeseen Implications

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Acknowledgment

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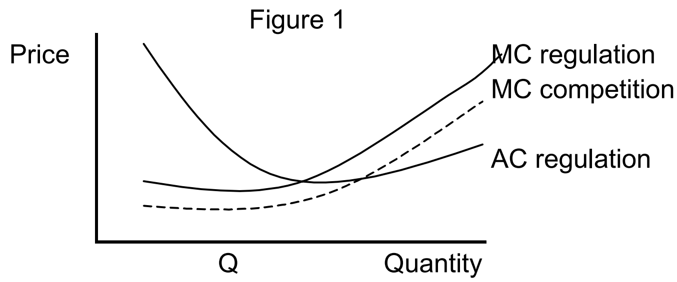
I. Restructuring—Theoretical Considerations

Under traditional cost of service ratemaking, regulated utilities are authorized to collect revenue to cover their costs of generation. Reasonable capital costs, taxes, depreciation, plus a rate of return, as well as fuel, operating, and maintenance costs, are all covered by the revenue requirement. The generating costs are less at some plants than others, and the costs of each plant are recovered at their appropriate levels. Thus the kWh from each plant do not cost the same, and ratepayers end up paying the average embedded cost (historical cost incurred) for the kWh consumed.

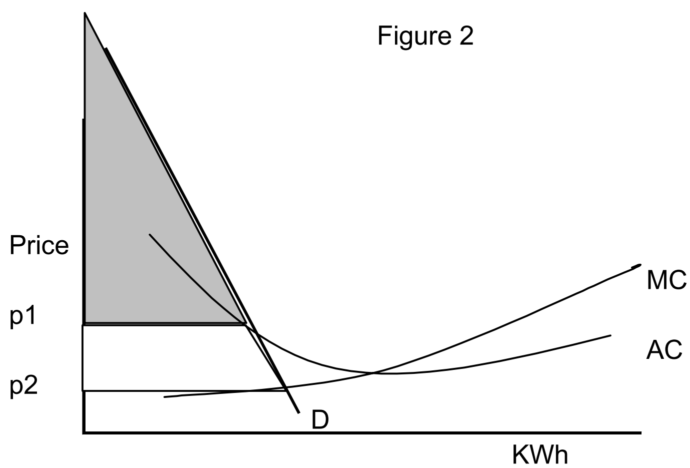
The desire for restructuring is fueled by the perception that additional kWh can be obtained at a cost (the marginal cost) that is less than the average cost paid under cost of service regulation. With the low gas prices that have been prevalent until recently, large industrial customers especially have been tempted to cogenerate, bypass, or support restructuring to obtain the lower energy prices available at the margin. The difference between average and marginal cost is especially obvious when a utility's embedded cost includes relatively expensive nuclear investments, or when cost-of-service regulation (or rather, lack of regulation) elicits inefficient and costly utility behavior.

The promise of restructuring is shown in Figure 1. The marginal cost curve (MC) at point Q is less than the average cost curve (AC). Thus additional kWh can be obtained at a cost that is less than the average. Note that in the situation where MC<AC, the average cost curve is actually falling. In the circumstance where lower marginal cost options are available, the utility could invest in them and lower its average price. Restructuring is not a necessary requirement for capturing at least some of the savings available from lower marginal costs.[1] Other arguments have been made that the MC curve itself will shift downward (to MC′), lowering prices due to the unleashing of competitive forces that will increase productivity in providing generation, bundle retail services now provided separately, give customers choices of power products with different attributes, and create demand responsive load where none exists today.

[1] Rates would have declined in both California and the United Kingdom, had restructuring not been implemented. See David W. Penn, "Deregulation Mythmaking Aside, the Answer is Market Structure," *Electricity Journal*, May 2000, page 52 and footnote 6. Rates would have fallen by 8-12% from 1996 to 1999 in California based on estimates previously made by our office at the time of the passage of California's restructuring legislation, AB 1890.

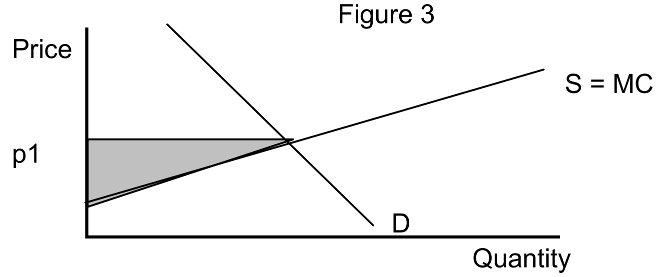


Consumer surplus is the difference between what consumers are willing to pay for an item, and what they actually pay, e.g. the area under the demand curve (D) above the current price. (See Figure 2) In theory under restructuring, if a lower price is possible, there will be a larger consumer surplus. Initially, at price p1 on the average cost curve, the consumer surplus is the shaded area. If it is possible to move the price to p2, on the marginal cost curve, the additional consumer surplus will be the hatched area). Welfare (consumer surplus) would be increased if a lower price could be obtained.



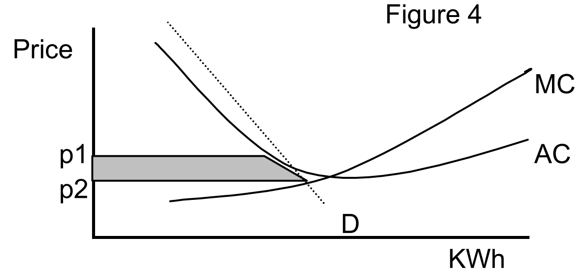
On the supply side, the mirror of the consumer surplus is the producer surplus. The area below the supply curve sums up all the variable costs of production. The area between the current price and the supply curve (the same as the marginal cost curve) is the producer's surplus, which goes toward fixed costs and profit. (See the shaded area in Figure 3).

Figure 3



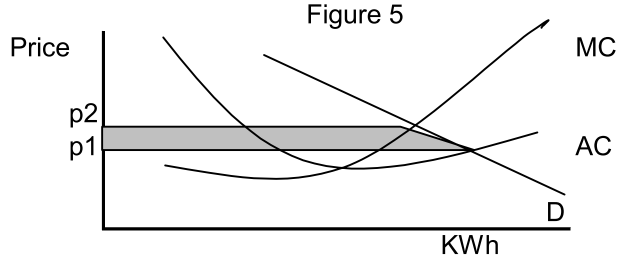
In contemplating moving from the average cost curve to the marginal cost curve, to obtain the benefits of lower marginal prices as shown in Figure 1, society must deal with the investments that are no longer economic (stranded costs). Simplified, this is the difference between the AC and MC curves, as shown in Figure 4. Thus the area of stranded costs is theoretically the same as the area of potential additional consumer surplus if the marginal cost curve does not shift downwards as shown in Figure 1. [2]

Figure 4



Before leaving this theoretical introduction we note the importance of the accuracy of the assumption that lower costs can be obtained under restructuring. If not, we have the situation shown in Figure 5, where p2 (after restructuring) is <u>higher</u> than p1 (before restructuring), and consumer surplus is negative (the shaded area). Consumers are worse off, because not only do they not pay the average cost for most kWh, but, under an irrevocable determination of stranded costs (either administratively or through divestiture)[3] the higher price (p2) is

Figure 5



[2] Stranded costs may also be less if shareholders are required to share in them or if they are financed at a lower rate than the utility cost of capital.

applicable to all the kWh for which stranded costs have already been paid. This is tantamount to paying twice for out-of-market fixed costs of existing generation.

II. Theory vs. Practice

Several restructuring experiments nationwide have already demonstrated that critical assumptions underpinning the promise of additional benefits from deregulated energy markets are not necessarily true. This section examines some of the lessons already learned. It is humbling to contemplate the prospect that this list is probably not exhaustive. What can go wrong will go wrong, in ways we never anticipated.

A. Assumption: Marginal cost is less than existing average.

As shown above, the assumption that marginal energy can be obtained at a cost less than the embedded average cost offered by the utility is the most critical assumption in restructuring. Without this prospect, restructuring has no chance for obtaining more customer surplus and thus a positive outcome for consumers and society as a whole. If this condition is not met, consumers will be worse off.

It is likely that marginal cost (regional market prices) are greater than average regulated cost for a number of Arkansas utilities (the one possible large exception being Entergy with its nuclear generation), especially if gas prices remain high for several years. Based on national experience, much of which is applicable to Arkansas, there are several reasons why market prices can be greater than regulated rates. A clear understanding of these factors is needed before commencing a competitive market.

1. Fuel price increases

Current oil and gas prices are increasing, and these prices have shown some ups and downs over time. If the benefits of restructuring are based on a forecast of low fuel prices, those benefits are likely to evaporate as fuel prices rise.

2. Supply shortage

During times of supply shortage, such as peak usage periods, the price in a competitive market will reflect a scarcity value. Electricity is a unique commodity, because the supply and demand must be balanced on an

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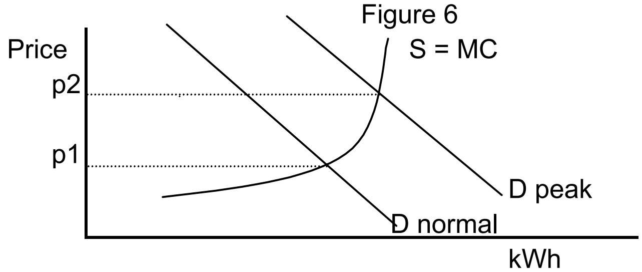
[3] This does not apply to physical hedges, discussed in the stranded cost section below.

instantaneous basis, with little storage capability. Furthermore, the consequences of lack supply/demand balance can be grave and widespread -- brown-outs, black-outs, and grid disturbances. An outage can cause significant disruption to the electricity-dependent economy, including far-ranging externalities. These factors mean that in times of supply shortage, a very high price can be extracted in a competitive market, far higher than anything experienced under traditional regulation. (The supply curve is almost vertical at high load levels --see Figure 6).

Very high prices have been experienced in a number of places after deregulation has been implemented. Alberta has had an almost continuous and worsening power crisis since 1998, with extremely high pool prices.[4] Experience in California demonstrates that deregulation should not be attempted during a period of shortage of electricity supply, especially if there is no real-time price signal to consumers.

Figure 6



A related lesson to be learned is that if the retail market structure is not clear, no one will build powerplants for the spot market. Alberta deregulated its wholesale market in 1996 but will not deregulate retail power until 2001. During this interim period, almost no generation was built. It is difficult to build generation when a spot market and a limited futures market are all that is present. No one had any idea how many retail customers they would have at the end of the transition period, so no one would build new generation to serve them. The transition (rate-freeze) period was also a contributing factor to the lack of new generation in California.

The high prices observed in the Entergy futures market in the summer of 2000 suggest that shortages may be developing in Arkansas (again possibly because

[4] An isolated pocket in the northeast corner of the Western grid, Alberta illustrates why restructuring is particularly tricky for an electrically isolated area. In Alberta, western grid prices are imported during heavy load hours because of a tie-line to British Columbia. However, Alberta can experience even higher prices than the rest of the West if the tie line is full and it experiences a localized generation shortage.

the market structure was not clear enough to allow construction) just as the restructuring process is beginning.

3. Prices of other inputs (emissions credits)

In a competitive environment, not only the fuel price but also prices of all inputs are components of the market-clearing price, applicable to all kWh sold. The price of emissions credits, needed by generators to permit their emissions of NOx and/or SOx, can thus influence energy prices. Especially in times of supply shortage, when semi-retired or high polluting units are called unexpectedly into service, the price of tradable emissions credits can also increase significantly. This factor was a significant contributing factor to California's high prices in the summer of 2000. [5]

4. Consequences if marginal cost exceeds average cost

If, for any of the above reasons or any other reasons not enumerated, the cost of additional power is <u>not</u> less than the utility's embedded cost, proceeding with restructuring can have large detrimental societal consequences. Under traditional regulation high-cost power on the margin gets diluted with other generation into the utility's average cost. Under competition, high-cost marginal power sets the price for ALL kWh sold in the market.[6]

The result is that restructuring can raise rates. If the high price comes on suddenly, as in California, ratepayers can end up paying twice, once for stranded costs based on very different price assumptions (even if powerplants are divested and purchased by new market players based on an earlier estimate of costs), and a second time for the new higher market prices.

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[5] See California PX Compliance Unit. "Price Movements in California Electricity Markets." Testimony for House Commerce Committee. September 2000. The prices can be exacerbated if unforeseen demand coincides with the completion of a compliance cycle, when emissions and credits have to be reconciled.

[6] Bilateral contracts and other contractual hedges would tend to escape the consequence <u>in the short term when they are actually in effect</u>, but they are still market-based prices. Theoretically, the cost of these hedges are based on expectations of future market prices plus an insurance premium. Economic theory suggests that the pricing of contractual hedges are based on all information available to the participants in those hedges regarding future market trends. Thus, expectations of future spot market prices form the basis for the longer term market prices.

B. *Assumption: Opening the market achieves movement to the MC curve and shifts the curve downward*

Assuming the marginal cost curve is lower than the average cost, the next most important assumption underlying restructuring is that opening the market will assure movement toward that MC curve (after a transition period) and will also unleash competitive forces that reduce marginal costs. Several market circumstances, however, may hinder this progress.

1. Wholesale Market power

While often attention is given in creating the restructuring model to mitigate potential market power of utilities (as has been done in Arkansas' legislation), other market participants can also exert greater weight on the market outcome than is characteristic of pure competition.

- In situations of supply shortage, the generators can demand top dollar and society is held hostage.[7] Market power issues are exacerbated in periods of tight supply.[8]
- The California model has scheduling coordinators, who coordinate between generators, marketers, and other large customers. Activities of these scheduling coordinators could also exhibit market power.[9]
- The agencies that implement restructuring may themselves significantly affect the market. The rules under which markets work are critical. Yet , there is no guarantee that the rules created by these agencies promote efficiency and full market participation. Indeed, some examples in California and elsewhere show that the rules may work against certain participants.[10] In

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[7] While it can be argued that this is the competitive market at work, in the theoretical model of pure competition there are more sellers (generators), smooth price responsiveness of supply (not a 3-year lag to build a power plant), price responsiveness of demand (not a 30-day lag until the bill is received, and an expensive stock of energy-guzzling machines and appliances to replace), and a storable commodity.

[8] A comparison of prices predicted under California restructuring with prices resulting in the first year of its operation showed that prices in the peak 10% of hours were consistent with "some strategic behavior by generators." See Robert L. Earle, Philip Q. Hanser, Weldon C. Johnson, and James D. Reitzes, "Lessons from the First Year of Competition in the California Electricity Markets," *Electricity Journal*, October 1999, p. 65.

[9] See California Public Utilities Commission, "California's Electricity Options and Challenges: Report to Governor Gray Davis," August 2, 2000, Chapter IV.

[10] For example, the California ISO now requires reserves on cogeneration loads, a departure from the practice under regulation, thus raising system costs for no apparent increase in real reliability. The CAISO also does not allow customers to sell only power that is surplus to their own loads

California, rules for bidding into ancillary service markets have had to be revised several times, as market participants have learned how to "game" existing rules. In California, the ISO and PX are private agencies with little option for public participation in decision making. Rather, their boards are composed of market participants, and they have "no duty to protect the public or consider the retail customer."[11] The utilities in California still under the rate freeze are not permitted to hedge their purchases with long term contracts, and are thus at the mercy of the PX prices.

- As a consequence of the market structure as implemented in California, during the peak of 2000 there was considerable underscheduling of requirements by utilities and of supply by generators in the Day Ahead market. This practice increased the amount of energy subject to last-minute resolution in the real-time market, increasing the financial burden on consumers of the resulting high real-time prices.

Even prior to the high summer prices of 2000 in California, simple observation showed that the market was not reflecting the marginal cost curve. "(P)eak prices are beyond the upper bounds of short-run marginal costs of producing at peak load levels observed under regulation."[12] The California ancillary service markets also exhibited characteristics of market power (with capacity payment for availability of reserves exceeding the energy payment available in the real-time market,[13] and the high prices of ancillary services observed in 2000 suggest thzt generators' profit margins are rising. Such results do not assure us that the MC curve has been reached.

2. Retail Market Power

Retail markets often are not competitive, particularly for small customers, because utilities' control over their billing and metering systems can make it

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into the grid, requiring them instead to either buy all and sell all, or to use the load internally and sell nothing. This rule has caused at least one cogenerator to reduce its output during the California power shortage. As stated in a recent publication, "Procter & Gamble can no longer provide any excess electricity to the grid -- even during emergencies." (*California Energy Markets*, August 4, 2000, p. 9) As another example, the requirement that generators be scheduled with certainty and reserve transmission capacity in advance to serve their maximum possible loads (as proposed by the Midwest ISO) works against wind generation, which has been easily scheduled into the system of integrated utilities for years with no problems.

[11] CPUC, Report to Governor Gray Davis, ibid., executive summary.

[12] Earle, et. al., ibid., p. 63.

[13] See Earle, et. al., ibid., p. 68.

difficult for competitors to serve small customers, and can raise the cost of serving them.

While metering and billing costs are relatively minimal to utilities, these are significant costs to small customers and their prospective energy service providers. These costs could easily be 5% of the total cost of energy provided to a residential customer by the energy service provider. If economies in this area can be realized, they can provide a significant savings to customers (e.g., shift the MC curve downward).

In essence utilities are using the regulatory process to raise barriers to entry against other retailers.

In particular, utilities in several states including New Jersey and California have adopted strategies to promote sending two separate bills to customers – one from the utility and one from the marketer (or at least to prevent the retailer from being the only entity that sends a bill) – to raise retail costs and assure that the utility has a billing envelope that it can use to sell other unregulated products and services. These strategies include miniscule credits to marketers who send their own single bill, as well as tariff terms and conditions related to deposits, timing of bill payment, treatment of uncollectibles, etc. Two New Jersey utilities even claimed that they were being deprived of a property right if they were not allowed to send a bill to customers for distribution services.[14]

3. Transaction costs

The pure economic model abstracts from realities such as transition costs and transaction costs.

- In California, the ISO alone (not counting the PX) has an annual budget of $200 million. That's roughly $20 per customer per year, exceeding the savings customers are likely to see in the near future from restructuring.
- New metering is required at many different points in the system. The California utilities had to install new revenue meters at their powerplants to meet the exacting requirements of commercial competition, and PG&E was also required to install new gas meters at electric powerplants. Individual large customers (to 100 kW in the UK and 50 kW in California) now need meters that record loads every 15 minutes. New computer systems must be built by a number of market participants to handle the output of those meters.

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[14] Michael E. Barrett and Purvez F. Captan, Ernst & Young, LLP, Prefiled Testimony on behalf of NUI Elizabethtown Gas Company and South Jersey Gas Company, New Jersey Board of Public Utilities Docket No. EX99090676, March, 2000.

- Utilities are installing major new modules on computer systems to deal with retail access issues. While some of these systems appear designed to provide them with competitive advantages when the markets open, others are genuinely needed to keep the records necessary for a restructured market, raising costs.
- Breaking the vertical utility into components creates a transaction cost and administrative cost for each entity to interact with the others. Each activity then needs to be priced separately. Where the utility had a centralized dispatch function, there is now a generation bidding and scheduling function and a (necessarily) separate distribution/retail load bidding and scheduling function. While such separation is needed to maintain competition, it is not cost-free. Similarly, the separation of distribution and retail functions may increase costs for services which the utility shares between the two functions (e.g., call centers).

4. Capital Versus Energy

The effect of deregulation is to increase the return required on investment capital by increasing the risk of generation. The result of this change has been to favor new technologies that are not capital intensive (e.g., simple cycle and combined cycle gas turbines) over more capital-intensive technologies with lower fuel costs (coal, renewables). Market forces requiring higher returns on capital are essentially pushing the shift to gas – which is likely to have the effect of further raising gas prices. We may thus be moving toward the MC curve, but the MC curve may be shifting upwards, not downwards, due to deregulation and gas generation.

5. Price Responsive Loads

One of the promises of restructuring is the promotion of loads that respond to real-time price signals. However, at least interim restructuring measures in most places have not promoted price-responsive load.

In fact, in an open market which flows power prices through to customers (e.g., California) most customers without special meters are in a worse position than before restructuring, because they do not know the price of the electricity that they are purchasing until after they have bought it. A consumer who had no idea that electricity in San Diego in June costs 15 cents a kilowatt-hour could not return it to the store for a refund once he/she has used it. One of the key requirements of a competitive market is perfect consumer information. While there are deviations from this exacting theoretical standard in most markets, the California electricity market has one of the greatest deviations of any power market, by giving the average customer no price information until the bill is sent.

Worse, the California utilities have actually responded to the new market by discouraging garden-variety time of use rates for their small customers. Both PG&E and SDG&E actually proposed to cancel residential time of use rates.[15]

Price responsiveness is not capturing great interest among large customers. Even a large fraction of California interruptible customers (who already receive discounts for the theoretical right to be interrupted) are not interrupting their loads when called upon, and many such customers are canceling their contracts at the first possible opportunity in November, 2000. [16] In Alberta, price responsive tariffs are not being well subscribed, and most interruptible contracts are being cancelled.

C. Assumption: The market will provide adequate supply

As part of restructuring, the balance of supply and demand that was required in a regulated environment is replaced by reliance on the market to provide adequate electricity supply. Bringing forth this extra supply is further complicated where the market offers no capacity payment. Rather, fixed costs are recovered only in the energy price, which can have uncomfortable rate design consequences for certain customer classes.

1. Boom and Bust

Under a restructuring plan that offers no capacity payment, such as in California, there is no assurance that supply will materialize. **The day-ahead market is the longest horizon seen in this competitive market.** In order to call forth enough supply, then, the short run prices have to be high enough for long enough that potential generators feel confident there is a demand for their investment. Since power plant construction has a lead time of several years, it is probable that consumers must tolerate high prices for several years before a glut of new generation materializes, and prices fall to levels too low to interest new generators. This is a recipe for a boom and bust cycle.[17]

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[15] SDG&E retained its residential TOU rates after a settlement, and PG&E's proposal is being opposed by the Commission's Office of Ratepayer Advocates and The Utility Reform Network, a residential customer group.

[16] Mark Golden, "Power Points: Interruptions are Windfall for SoCal Edison", *Dow Jones Newswires*, September 22, 2000.

[17] Some have called for a capacity payment, to attain long-run efficiency in supply. See Roger L. Conkling, "A California Generation Capacity Market," *Electricity Journal*, October, 1998 and Andrew Ford, "Boom and Bust, Understanding the Powerplant Construction Cycle," *Public Utilities Fortnightly,* July 15, 2000, pp. 36-45. Ford claims that an energy-only price leads to such

2. Hedging

Allowing utilities to enter into long term contracts is one solution to hedge short-term price variability, and assure generators of a long-term market. There are two types of hedges, commercial hedges, which are based on expectations of future market prices, and physical hedges, backed by generation, which may be provided under a modified cost-of-service structure (discussed in the stranded cost section below). Commercial hedges will mitigate price spikes, but under economic theory they do not mitigate the overall price level, since the cost of a hedge is theoretically based on all available information on future market conditions available to market participants, plus a premium for insurance.

3. Supply Shortages

There is a concrete lead time between the realization that additional generation is required and when it can materialize. This lead time differs for different technologies, but it is difficult to collapse this time frame to less than 1-2 years if something physical has to be built (requiring permits, public input, etc.). Getting new supply online can be further complicated if turbine manufacturers have significant lead times, as at present.[18] In that situation consumers must endure higher prices not only until a generator realizes that there is an investment opportunity, but also until that investment opportunity beats out opportunities in other parts of the country or the world.

Because consumers are held hostage during a period of supply shortage, there is political pressure to obtain new generation quickly. This pressure, evident now in California, can take the form of attempting to speed up normal environmental review, public input, and other established permitting procedures. In such a situation restructuring has the potential to lead not only to periods of electricity shortage and high prices, but also to leave the legacy of hastily reviewed new power plants and possible sub-optimal consequences.

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cycles, while capacity payments do not. However, An explicit capacity market was included in the design of the PJM pool, but even so, it is not clear that it has cooled off the response of PJM's energy markets to power shortages, as energy prices have still reached levels in excess of 50 cents per kWh during power shortages.

[18] Lee S. Langston, Gas Turbine Industry Overview, Market Results for 1999. International Gas Turbine Institute. www.asme.org/igti/techreport/tr00_oview2.html

D. Assumption: Separating the electricity system into parts will have no adverse consequences

To create competition in the electric industry, restructuring separates the vertically integrated utility into two or more separate parts, some of which may be sold to non-utilities, and some of which may become non-regulated affiliates. Implicit in this division is the assumption that there will be no adverse consequences for cost or reliability from this separation, e.g. there were no economies of vertical integration for utilities. [19] This assumption should be carefully examined, as several examples provide evidence to the contrary.

1. Cost consequences

Separating the utility into separate parts, such as transmission, distribution, generation, and customer services, that still need to communicate with each other can entail additional administrative costs. For the functions that become part of the competitive market, for example generation or customer services, communication with the monopoly utility which remains ratepayer funded must then be arms-length transactions, protected by affiliate rules that assure equal opportunity for all competitors. Such rules must require separation of costs, brand, administrative offices, customer database, and reporting from the utility, adding to ultimate costs.

As another example, creation of separate markets seems to have increased the price for services that the integrated utility provided less expensively. With creation of a separate generation and ancillary services market, for example, evidence shows that the cost of ancillary services in California has gone up, to 12% of the PX energy price in the first year, well beyond the 3-5% of energy prices that was the prior engineering estimate.[20]

2. Changes in Agency Policy

The development of ISOs and RTOs and the development of ancillary service markets has balkanized functions that were integrated within utilities, raising costs. As described above, the ISO in California has changed the integrated utilities' policy to implement a new, more expensive policy to require reserves to be held against load normally fed by cogenerators. This policy, requiring more

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[19] This is contrary to evidence provided in Lawrence J. Hill, "Is Policy Leading Analysis in Electric Restructuring?",*Electricity Journal*, July, 1997, p. 53-54.

[20] Afzal S. Siddiqui, Chris Marnay, and Mark Khavkin, "Excessive Price Volatility in the California Ancillary Services Markets: Causes, Effects, and Solutions," *Electricity Journal*, July 2000, p.65. The ISO has made subsequent changes to market rules that have reduced this amount somewhat.

reserves than were held by the vertically integrated utility, will obviously increase costs. The California ISO has also implemented statewide reliability standards with a consequence that Pacific Gas and Electric would need to consider the cost-effectiveness of transmission upgrades in situations where PG&E would not have built projects under its old practices. Rules that make the integration of intermittent generation more difficult under open access transmission than under the vertically integrated utility also raise costs to environmentally friendly renewable generators.

3. Reliability Consequences

Experience has shown that dividing the integrated system into pieces can have adverse consequences for reliability due to several factors:

a) Operation of the Grid

Creation of a new grid operator in California, the ISO, was bound to have growing pains. Initially the descriptions of operating limits for each transmission line segment were not written down exactly for the ISO by each utility transmission owner, as the utility's operation staff knew from experience how much each line could be stressed during peak periods. Lacking such detailed instructions, the ISO, who is essentially driving a car that belongs to someone else, took fewer risks than the utility would have, thus operating the system at a lower capacity than the utility had previously.

Having two levels of transmission operation, the ISO and the utility, can also create more chaos and less timeliness with respect to outage repair than under one utility. Unclear delineation of responsibility and communication between the ISO and PG&E's personnel were partially responsible for an extended 4-hour transmission outage affecting the city of San Francisco on December 8, 1998.[21]

b) Generation maintenance

As an integrated utility, generation maintenance was scheduled in consideration of the overall system. As a result, simultaneous planned outages of critical generators were avoided. With generation in the hands of non-utility suppliers, there is not necessarily any coordination of maintenance schedules, indeed, such coordination could be considered market collusion. Thus multiple outages were

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[21] Chong Chiu, et. al., Performance Improvement International, "An Independent, Full Scope Root Cause Investigation of San Francisco December 8, 1998 Outage," on behalf of the Consumer Services Division of the California Public Utilities Commission, April 22, 1999, p. 46-49.

a contributing factor to supply shortages in high prices during California peak periods this summer.[22]

4. Lack of Efficiency Incentives

With the utility split into parts, costs to one portion of the system can be simply passed through to another, with no incentive to minimize ratepayer consequences. For example, with a separation of the transmission and distribution systems,[23] transmission losses are a pass-through to the distribution business. The transmission utility has no incentive to reduce transmission losses, as its costs are simply passed through to ultimate consumers. Similarly, the distribution utility treats its own losses as a pass-through. No one entity has the responsibility to minimize costs to the end-use customer, even through such an elementary engineering trade-off as the one between capital costs (for higher quality transformers and larger wires) and losses.[24]

5. The Disenfranchised Customer

A disconnect is created between retail customers, who interface with a retail provider, and the monopoly suppliers of inputs to their electricity service. Unlike the situation with long-distance providers of telephone service, customers will have little connection with the transmission utility (and possibly not even the distribution utility, depending on the market structure). The retail provider will not be responsible for transmission or possibly even distribution service levels, and customers will have no leverage about these issues, if they are even aware of them. Under the regulated structure the integrated utility was responsible for all aspects of end-use service and reliability. With its division into parts, no one is ultimately responsible, and the customer has become disempowered to effect change.

With the separation of the transmission function into a FERC jurisdictional area, as in California, the customer is further distanced from cost and reliability decisions made about the transmission system. Changing jurisdiction from the state to the federal level means that the states have less influence on future transmission and market design policies which will be addressed in line with

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[22] CPUC, Report to Governor Gray Davis, ibid., Chapter II, section 4.

[23] In Alberta, TransAlta retained its transmission system and sold its distribution system to UtiliCorp, who is now proposing to subdivide that and sell off the retail portion of the distribution business.

[24] Performance-Based Ratemaking (PBR), with its strong incentives to avoid capital spending, can make these problems worse.

federal priorities. Furthermore, the effort required for customers to be heard at FERC is much more burdensome than to contribute input at the state level.[25]

III. Other (Possibly Unforeseen) Impacts of Restructuring

A. Rate Design Becomes More Energy-Oriented, To the Detriment of Large Industrial Customers

In many states, including Arkansas, regulation has treated variable costs as energy and fixed costs as capacity. A large portion of the fixed costs are then allocated to only a few hours during the year. For example, the average-and-peak method used by Entergy and SWEPCO in Arkansas allocates approximately 50% of the fixed costs based on four summer peak hours, while the Co-ops allocate an even larger fraction based on these four peak hours. Interruptible customers are assigned little or no peak responsibility. And discounted economic development rates are provided to "use up" the off-peak valley. Because existing regulation allocates so much of the utility system's fixed costs to a few summer peak hours, it allocates a large portion of the system cost to residential customers.

The market to date has turned out very different from the regulatory treatment of capacity. The market price that has been developing in most restructured markets does not have traditional demand costs and demand charges. Rather, electricity spot markets are hourly energy markets, and electricity futures markets tend to be traded as strips (e.g., an equal amount of energy, six days a week, sixteen hours a day is one typical product). Interruptible customers are expected in many markets to self-interrupt if they do not like the prices being paid, rather than receiving a regulatory rate credit.[26]

The industrial imperative to restructuring apparently labors under the misconception that someone else would pay the fixed costs of capacity while industrial customers receive "cheap" spot market electricity that could be

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[25] Not only is FERC physically farther away and engaged in a more legalistic procedure than many state Commissions, but in states such as Wisconsin and California, intervenor compensation is available to customer groups for participation in cases at the state commission. No such compensation is available for workshops attended at the California ISO, or at FERC.

[26] The theory that load reduction benefits all customers (see below) may suggest paying a credit above the rate to an interruptible industrial to share that benefit between the customer and the system, but the credit would only be paid when the customer was called upon and actually interrupted its load.

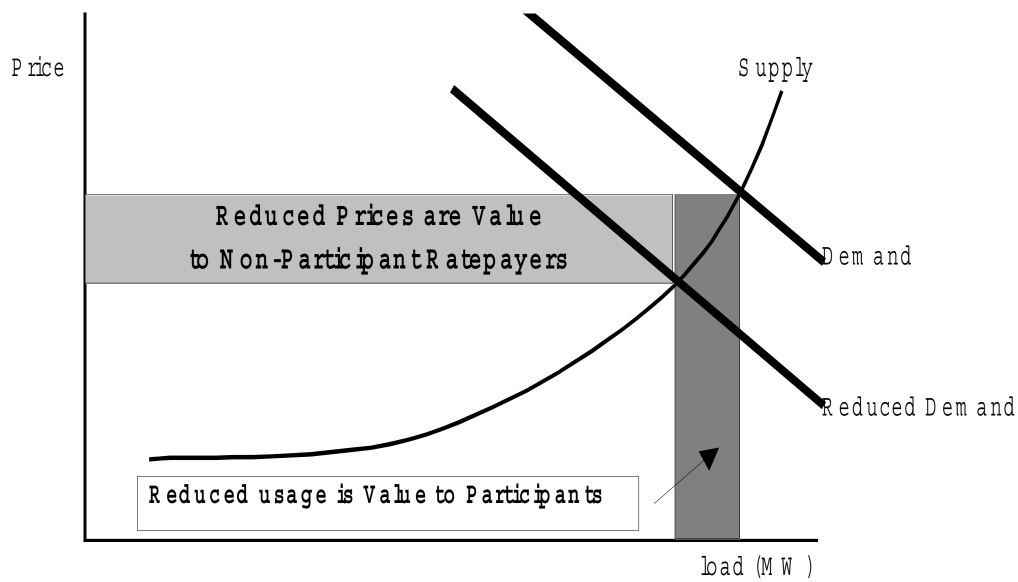
provided once capacity costs were not fully recovered in market prices. That has generally not occurred to date.

As a result, the market has not been so kind to industrial customers. In England and Alberta, industrial rate increases have occurred after restructuring. In Alberta, interruptible rates were largely abolished, after customers complained about the increasing number of interruptions. In San Diego, while the headlines are about residential rate increases, industrial rates have increased at a higher percentage rate because distribution costs, which did not increase, are a much smaller fraction of their rates. Thus, we no longer can assume that restructuring is necessarily good for its most fervent advocates.

B. Energy Efficiency and Load Shifting Investments Become More Cost-Effective

Under restructuring, the price of the last kWh affects the price of all kWh for all customers. In this situation energy conservation not only reduces the demand, but also impacts the price of all kWh purchased.[27] (See Figure 7, which shows a simplified analysis for a given hour). The price drops if energy efficiency investments are used to reduce demand, but the participants (who made the investments) only receive a portion of the savings. The cost of electricity to all consumers, including non-participants, is reduced.

Figure 7



[27] R. Ferguson, "The Value of Energy Efficiency in Competitive Power Markets," Clean Power Journal, Summer, 1999, p. 5.

The relationship of the value of load reduction investments to the market price has been measured in California, and a similar study is underway in for the PJM pool region. –Because of the reductions to the market price that are induced by load reduction, load reduction has a value of about twice the market price at low load levels rising to three times the market price during typical summer afternoon hours and five times the market price at peak. [28]

In evaluating the cost-effectiveness of new investments in energy efficiency and load shifting (DSM), the impact of this potential price change must be incorporated, as it is a positive externality that is the consequence of demand reduction. Such a consideration is likely to show that higher levels of DSM are appropriate than were justified under traditional methods. Programs to promote electricity use – even off-peak, such as heat pumps, will be even less justified because of their effect on costs.

Since experience has shown that during peak periods of shortage, other factors such as market power contribute to especially large price increases, the value of demand reduction in these peak periods is likely to permit sizeable savings. Thus DSM programs that affect peak usage, such as replacement of old, inefficient window air conditioners for poor people, standards or rebates for purchase of efficient new systems, and air conditioner and water heater load management, will show large benefits to society as a whole.

This externality also means that the distribution company should not conduct rate design in isolation from other considerations. While a distribution company may find that a customer charge is desirable to recover certain wires costs, consideration of these external effects should temper this view.

IV. Stranded Costs?

Act 1556 of 1999 sets forth complex procedures and formulas to ascertain and measure a utilities' so-called "stranded costs," as a result of electric restructuring. The statute favors methods that mimic "real world" market prices as much as possible. Methods recommended include asset sales, stock valuation, and capacity sales. However, there are still many variables that go into the calculation and, if appropriate, the approval of stranded costs. As the current

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[28] W. B. Marcus and G. Ruszovan, "Cost Curve Analysis of the California Power Markets," September, 2000. These values assume that the utility retains about 40% of its generation as a physical hedge. For a utility which has no physical hedges, the values of conservation are even greater as a percentage of the market price.

docket before the Commission, No. 00-177-U, demonstrates, there can be great disagreement over the existence, let alone the extent, of stranded costs. These disagreements will undoubtedly result in protracted litigation, and therefore, significant cost.

The administrative determination of stranded costs generally compares the book value of existing generation to the cash flow that such generation could produce. The cash flow is calculated by running a model to determine the market price associated with the energy and capacity produced by each generating plant through the end of its book life (as long as 2025 to 2035 for some plants). This model requires tens of thousands of data inputs. The model requires the trajectory of the future price of natural gas, oil, nuclear fuel, and various types of coal prices, the characteristics of all existing and new plants (heat rate, forced outage rate, variable O&M costs) on a large area transmission system, and a forecast of the types of new plants that will be built and their capital costs, fixed and variable O&M costs, capital additions, and fuel costs.

For each power plant owned by each utility, forecasts must be made of availability or capacity factor (forced and maintenance outage rates), fixed O&M costs, capital additions, variable O&M costs, heat rates, fuel prices, and inventory levels, applicable to that plant. The costs of running each plant are compared to the revenues received from running each plant and are then present valued.

It is clear that this method requires a massive forecasting capability, where the best" modeler (the utility with its ratepayer-funded employees) usually can win.

The following are among the key input variables that will drive the utility's stranded cost claims under an administrative determination:

- **Market prices of power and fuel costs.** Stranded cost studies in a number of states had market prices under 3 cents per kWh for baseload power in real terms for the indefinite future. A number of utilities received stranded costs based on those low numbers.

- **New capacity cost estimates.** Utilities often provide low estimates of these costs to make existing capacity look cheap. To provide examples, Houston Light and Power made the ludicrous assumption in its most recent rate case that combined cycle capacity could be built today for $300/kW, while Virginia Power assumed that new combustion turbines would be $200/kW (in real dollars) forever. Other utilities have made more subtle mistakes to bias their analysis, such as assuming that existing combustion turbines will require capital additions but new ones will not.

- **Plant operation efficiency levels.** Utilities often assume that there will be no productivity in the future operation of their units. The ability of a competitive market to unleash competitive forces that improve productivity is one of the central, almost ideological, tenets of supporters of restructuring. Yet utilities that make administrative stranded cost estimates often assume that productivity is negligible or offset by plant aging.

- **Decommissioning costs and life extension.** In administrative determination of stranded costs, utilities often assume that plants cannot last beyond their life and must be decommissioned to close to a "greenfield" state when retired. This has the impact of giving all benefits of life extension to shareholders.

- **Propriety of recovery of administrative and general costs.** Utilities have a strong incentive to shift to ratepayers a wide variety of administrative costs including costs which must be borne by all competitors and costs of developing a presence in the competitive market. Recovery of the costs of building a competitive presence from ratepayers is wrong, and recovery of other administrative costs may be highly questionable. In shifting these costs to ratepayers, utilities may either identify these costs as "stranded costs," or they may try to move marketing and generation-related costs into the less competitive distribution area as part of "unbundling."

The utilities are required to estimate stranded costs in this proceeding, but we must be very careful to realize that these are just estimates, and probably low estimates. Table 1 presents the hypothetical case of valuing a coal plant administratively. The 1000 MW plant has stylized characteristics – coal fuel and other variable costs (e.g., SOx credits) of $15/MWh escalating at 3%, non-fuel O&M of $30/kW-year and capital additions of $10/kW-year escalating at 2.5% general inflation, a 20-year remaining life, and decommissioning costs of $100 million (nominal) at the end of that life. For simplicity in illustration, a 40% combined federal/state tax rate is used and it is assumed that state and federal depreciation parameters are the same.

The administratively determined value of this hypothetical plant (using these parameters and a 9% discount rate for illustration) is highly dependent on market prices and fuel prices[29]:

[29] By comparison to all of these estimates, the Mohave coal plant, which has higher operating costs than my example here and which is required to spend hundreds of millions of dollars to install a new scrubber in 2006 to keep from polluting the Grand Canyon, sold for about $530/kW this spring before the California price spike, and the Centralia coal plant in Washington, also facing an investment in a new scrubber, yielded over $400 per kW in 1999.

Market price (escalating at 4%/year)	Coal Plant Value ($/kW)
$25/MWh	$210
$30/MWh	$427
$35/MWh	$645
$40/MWh	$862

Moreover, for the same revenue estimate, other factors are important. A 10% reduction by a new owner in O&M and capital additions per year would increase the value by $26 million. Assuming that prices will be $30/MWh in the long run after a two-year spike to $50 in year 1 and $40 in year 2 adds $94 million to the plant's value.

What this means is that any administrative determination of stranded costs is likely to be wrong.

That leaves the policy-makers with two options: divestiture and physical hedges. It is clear that divestiture has provided better (i.e., higher) market values than was originally expected through administrative determination virtually everywhere that it has been applied. New owners believe that they can achieve synergies, unlock productivity savings, and cut administrative costs, and have therefore provided bids that exceeded original stranded cost estimates in many places.

Nevertheless, the volatility of the power market is teaching us a lesson – to retain some generation (particularly baseload generation that has fewer risks than nuclear generation such as coal) under physical hedge, rather than valuing all generation once and for all, transferring it to an affiliate, and letting the affiliate sell it at an unregulated price. Under this kind of physical hedge, generation may be revalued upward using a relatively conservative forecast (although it does not have to be). The generation is then sold into the market, but the utility's payments for generation is based on a cost of service analysis (using the new marked-up value if applicable). Differences between the market price received and the cost of generation would be preponderantly flowed through to ratepayers (although a small share to the utility could provide incentives for efficiency). [30] This not only gives ratepayers a hedge, but reduces the incentives

[30] For example, in California, Southern California Edison is proposing to retain its hydroelectric plants within the utility, but will mark them up to approximately twice book value (to offset other stranded costs) and will earn a return on the new higher value, while sharing 90% of the difference between revenues and costs (including a return) with ratepayers. Two different variants of this idea – one which leaves generation within the utility and the other of which transfers it to an affiliate but with a 40-year contract to provide power to ratepayers using a

of the utility to exercise market power with the retained generation. The benefits from the revalued generation should be spread to all ratepayers – both those staying with the utility and those leaving – so as not to distort the retail market.

An intermediate option between divestiture and physical hedging is divestiture with a sales contract back to the utility on a cost-based or at least capped basis for a period of several years. This option is being undertaken in Nevada at the present time.

V. Administrative Burden

The schedule adopted by the General Assembly in mandating retail choice in Arkansas was admitted at the time to be "aggressive." It required dozens of proceedings before the Commission. Some of these establish rules for filing rate unbundling proceedings, requesting stranded cost recovery or transition cost recovery, licensing energy service providers, and measuring market power, as well as rules governing affiliate transactions, electronic data exchange, consumer education plans, consumer protection, energy service providers' relationships with customers, pricing of competitive services, etc. There are also more than twenty dockets that address the actual rate unbundling for each utility, and more than twenty dockets that will address the functional unbundling for each utility. There may be that many dockets to assess each utility's market power, and each utility's request for transition cost recovery. There are many other proceedings that are ongoing, or must take place in the future, in order to assure that open retail access occurs by January 1, 2002, as mandated by the legislation.

The Commission, its Staff, and all others involved in the process have been extremely diligent in pursuing their obligations in these myriad proceedings. However, it appears now that the administrative burden is becoming too great. The heavily taxed resources of the Commission, its Staff, the Attorney General, and others, have been strained beyond their limit. Already, many of the rate unbundling proceedings have been delayed, some indefinitely. The original schedule appears at this time to been overly optimistic, and unworkable. It does not appear that everything that the General Assembly ordered to be done can be done in the prescribed time.

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largely cost-based index – have been proposed for hydro generation owned by Pacific Gas and Electric Company.

VI. Summary and Conclusion

The General Assembly appears to have passed the deregulation legislation based upon certain assumptions, the primary one being that deregulation will lower prices for some, if not all, electric energy, consumers. As is shown above, it appears that it is time to rethink these assumptions. First and foremost, if costs are already below market prices, the rationale for deregulation is tenuous. The initial experience in other jurisdictions seems to suggest that deregulation may actually increase prices, rather than lower them.

It is also important to recognize two somewhat unexpected results. First, other jurisdictions' experience shows that deregulation may lead to greater percentage increases in prices for industrial customers because an energy-based market will be less generous to them than regulators have been in the past. Second, the advocates of markets have told us that deregulation will bring us the best of all possible worlds with respect to energy conservation, where market-based investments will be made. Instead, the structure of deregulated electricity markets is likely to lead to supply curves that create a greater social value to energy efficiency and load shifting than is measured by the market prices themselves. A regulatory structure needs to recognize this value and encourage investments in efficiency.

There are also issues of market power, transaction costs, lost economies of scale, transition costs, and stranded costs. When coupled with the experience in other areas that competition has not resulted in lower prices, they suggest that deregulation may not be the panacea it was initially considered. Finally, there is a great question whether it is administratively possible to establish retail open access by January 1, 2002.

In view of these questions that have surfaced over the period since the passage of Act 1556 of 1999, moving to retail open access and abandoning cost-of-service regulation of generation on January 1, 2002, is not in the public interest. The date for competition should be pushed back for several years. Pushing back the date will enable the Commission, the General Assembly, and the other participants to have more experience in the wholesale market, and to see other states' experience in the retail market. It will allow the General Assembly to review the law, in light of the nation's experience. After that additional experience and knowledge, the General Assembly and the Commission will be much better able to ascertain whether going to retail open access at all is in the interest of the people of Arkansas.