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BEFORE THE ARIZONA CORPORATION COMMISSION

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Commissioner

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. U-0000-94-165

AARP cannot give direct testimony in the evidentiary hearing on issues related to stranded costs in accordance with the Procedural Order dated December 1, 1997 and subsequent amendments. AARP is submitting their position on stranded costs with original and ten copies of AARP's publication "STRANDED COSTS and MARKET STRUCTURES in the ELECTRIC INDUSTRY."

Respectfully submitted this 9th day of February, 1998.

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A WHITEPAPER ON

Stranded Costs and Market Structures in the Electric Industry

AARP

AARP is the nation's leading organization for people age 50 and older. It serves their needs and interests through information and education, advocacy, and community services provided by a network of local chapters and experienced volunteers throughout the country. The organization also offers members a wide range of special benefits and services, including *Modern Maturity* magazine and the monthly *Bulletin*.

Section One

Stranded Costs *in the* Electric Industry

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Section One
STRANDED COSTS

Introduction

What Are Stranded Costs?

As electric utilities throughout the United States are exposed to increasing levels of competition in generation, they are at risk of incurring *stranded generation costs*. Stranded generation costs, also referred to as "stranded investments" or "transition costs," can be defined as the difference between the fully-competitive market value and the regulated book value of all of a utility's electric generation-related assets. Stated another way, stranded costs represent the *uneconomic* portion of a utility's power plants, long-term power-purchase contracts, fuel supply contracts, generation-related regulatory assets, and deferred demand-side management (DSM) program expenditures[1] that are not recoverable under competition. In short, stranded costs "are the [net] sunk [generation] costs plus unavoidable prospective costs [associated with a utility's generation] that cannot be recovered in a competitive market."[2]

To say that utilities are at risk of "incurring" stranded costs is somewhat misleading. The existing uneconomic costs associated with a utility's generation assets have already been incurred and are presently part of its regulated embedded costs of service. Therefore, *all* existing uneconomic generation costs are currently recovered through the bundled rates paid by all retail customers.[3] As such, these uneconomic costs are not yet "strand*ed*." Rather, they are "strand*able*," and will only become "strand*ed*" (i.e., at risk for non-recovery) if there is retail competition and the utility begins selling its generation services at market prices.

There are four general categories of stranded generation costs:

- **Generation assets**: Capital invested in generation assets could become unrecoverable if market clearing prices are not high enough to support full recovery of variable production costs (including fuel), fixed operation and maintenance costs, and all of the capital-related costs.
- **Regulatory assets**: Generation-related "regulatory assets" include (but are not limited to) reserves for various types of deferred costs, some of which may be related to: 1) the phase-ins of new power plants, 2) nuclear plant decommissioning costs, and 3) deferred income taxes. Some of these regulatory assets may already be included in a utility's current rates, while others may not. Under traditional regulation, a utility would normally be permitted to collect regulatory assets not yet in rate-base. Thus, regulatory assets, including those not yet in rates, will contribute to stranded costs. Depending on the fraction of stranded costs paid by a utility's ratepayers and on the structure of the cash flow from the stranded cost recovery charge, the inclusion of *all* regulatory assets in stranded costs could cause a utility's rates to increase above their current levels.
- **Liabilities**: Long-term legal obligations, including purchased-power contracts and fuel supply contracts, could exceed competitive market clearing prices for comparable goods and services.
- **Deferred demand-side management program expenditures**: Deferred expenses associated with utility-sponsored demand-side management

programs may be uneconomical to some extent if the cost incurred to lower demand through the program exceeds the market price of power saved by the programs.

Why Should Consumers Be Concerned about Stranded Costs?

Consumers should be concerned about the estimation and the allocation of stranded generation costs because the approaches should be *equitable* and should allow all consumers to see benefits from electric industry restructuring as soon as a restructuring plan is implemented in their state. However, during the period when stranded costs are recovered, these benefits can *only* be achieved, first, by properly estimating stranded costs and, then, by sharing them equitably between ratepayers and utility shareholders.

As explained above, all retail ratepayers are currently paying for 100 percent of their utility's uneconomic (i.e., potentially strandable) generation costs. If there were retail competition, their utility would unbundle its rates and price its generation at market value instead of at its embedded cost of generation. Customers could purchase electric generation from either their local utility or other generation suppliers at the market price. However, they would only benefit from retail competition if their local utility's stranded generation costs (the difference between the market price and the embedded cost of generation) were shared in some fashion between its ratepayers and its shareholders (and taxpayers[4]). The rates would decrease by the amount of stranded costs paid by the shareholders. In other words, *if the utility were allowed to continue to recover 100 percent of its uneconomic and now-stranded costs from the customers served by its distribution system, then these consumers would not see **any** reduction in their electricity costs* relative to the situation in which present rate-setting practices continue unchanged.[5]

In short, if 100 percent of a utility's stranded costs are paid for by its ratepayers under retail competition, then they will not see any benefit from increased competition in the electric generation market until the stranded costs are fully recovered. They will pay the market value for generation plus 100 percent of stranded costs, a sum that will exactly equal the utility's current regulated cost of generation, by definition. Even if the generation market becomes extremely economically efficient due to competition and the market price for generation becomes very low, all of the benefit of the lower market value will be negated by the full recovery of the stranded costs, which will necessarily increase as the market price decreases.

Thus, consumers should be concerned about how stranded costs are *calculated* and, then, *allocated* between ratepayers and shareholders because these factors will directly impact the extent to which they will pay lower electricity costs during the stranded cost recovery period. Consumers should ensure that the ways in which stranded costs are dealt with are equitable and will have a positive impact on their bills in the future.

Methodologies for Estimating Stranded Generation Costs

An Overview of the Methodologies for Estimating Stranded Generation Costs

There are generally two broad approaches that are discussed in U.S.'s restructuring forums for calculating stranded generation costs: *the market valuation approach* and *the administrative valuation approach*. The market valuation approach would rely on auctions, sales, or spin-offs of generation assets to ascertain their market values, whereas the administrative approach would rely on forecasting and modeling to determine the market prices of generation from a utility's system. The names of these two approaches may lead one to think that they embody radically different techniques and philosophies for calculating stranded generation costs. However, this is not necessarily the case. The two basic inputs to *both* approaches are: 1) market prices (actual and/or estimated) of either generation assets or electricity (kWh), and 2) the embedded costs of generation assets or electricity (kWh). Furthermore, *both* approaches require varying degrees of additional input data from the generation market and involvement from regulators.

The Market Valuation Approach √

A market valuation approach is when a utility's stranded costs are based on the differences between the *actual* auction, sale, or spin-off price of each of the utility's generation assets and the actual embedded cost of each of the utility's generation assets. In a perfect market, the sale price (which defines the market value) of each generation asset would reflect each buyer's estimates of the future costs and benefits of running the plant. Specifically, "the sale price [would] equal the buyer's expectation of the discounted[6] ... present value of the anticipated revenue stream less the present value of the future operating costs, plus the salvage value, if any."[7] If an asset's market value is below its depreciated book value, then this difference is a stranded cost. If an asset's market value is above its depreciated book value, then this difference is a negative stranded cost, which should be used to off-set the positive stranded costs associated with other assets.

Below is a list of the advantages and disadvantages of the market valuation approach, each of which are discussed in turn

Advantages

- The calculation of stranded costs would be relatively straightforward.
- The calculation of stranded costs would be final.
- The divestiture of generation assets required by the approach might mitigate the potential exercise of vertical and horizontal market power[8] in the future generation market.

Disadvantages

- The stranded cost results could be affected by the maturity of the competitive generation asset market.
- The divestiture of generation assets required by the approach might increase the potential exercise of horizontal market power in the future generation market.
- The stranded cost results could be affected by the amount of the utility's as-

sets (or a neighboring utility's assets) that are to be sold over a given period, as well as the timing of each sale.

- The approach cannot accommodate a true-up mechanism. (This is the flip side of the advantage that the calculation of stranded costs would be final.)

The market valuation approach has the advantage of making the calculation of stranded costs relatively straightforward because it requires actual divestiture of generation assets, which would yield *actual* market prices of the assets.[9] Thus, regulators would not be required to estimate the future market prices or embedded-cost-based rates of generation in order to compute stranded costs. Furthermore, since the sale price of each generation asset would be final, so too would the calculation of stranded costs. There would be no need to ensure that the regulators' initial estimates of market prices for power seem reasonable, nor would there be a need to revise (i.e., "true-up") their estimates on an ongoing basis to reflect actual data.

By requiring the auctioning-off of a utility's generation assets to independent, deregulated companies, the market valuation approach may mitigate the potential exercise of vertical and horizontal market power in the future generation market.[10] A generation supplier's ability to exercise *vertical* market power in the future generation market would stem from the fact that the generation supplier would also own transmission and distribution facilities, which are monopolies. For example, the generation supplier might deny other competitive suppliers access to its transmission and distribution facilities, and then overcharge consumers in its distribution service territory for the power from its own generation facilities. Requiring owners of transmission and distribution facilities to divest their generation facilities could help to mitigate vertical market power. Other factors that could also help to reduce vertical market power include: 1) the establishment of an independent transmission system operator (ISO) that would operate under the principles set forth in the Federal Energy Regulatory Commission's (FERC's) Order 888; 2) FERC's open and nondiscriminatory transmission access rule; and 3) the transmission "expansion obligation" provision in FERC Order 888. However, regulations and existing anti-rust laws may *not* sufficiently mitigate vertical market power.[11]

A generation supplier's ability to exercise *horizontal* market power in the future generation market would stem from a combination of factors, including: how much of the region's generation supply is owned by the supplier, the types of generation facilities (e.g., baseload, cycling, peaking) that it owns relative to the types of facilities in the region and the types needed to meet marginal load, the physical boundaries of the regional market, regional transmission capacity constraints, the physical location of generation facilities and load centers in the region, etc. If all utility generation assets were sold to many small buyers such that no single buyer's ownership would provide it with the ability to charge more than fully competitive prices, then divestiture would mitigate horizontal market power.[12]

Some regulators, utilities, and stakeholders are considering using divestiture as a means of establishing a *quid pro quo* with utilities, whereby utilities would be able to recover more of their stranded costs from ratepayers as they divest more of their generation assets. In other words, as the percentage of a utility's divested generation assets increases, the percentage of stranded cost recovery from its ratepayers would increase.[13] However, divestiture could also have some potentially serious drawbacks for ratepayers that should be addressed *before* electric utilities are provided with ratepayer-funded incentives to divest their generation assets. (These drawbacks are discussed at greater length below.) Thus, in considering whether or not to use a *quid pro quo* approach, state regulators must ensure that doing so would not end up costing ratepayers more in the long run than if there were no divestiture. The ways in which the market valuation approach and its use of divestiture could end up costing ratepayers more are discussed below.

One potential disadvantage to the market valuation approach is that the stranded cost results could be affected by the maturity of the competitive generation market.[14] If there are relatively few potential buyers of existing generation units in a region, then the generation asset market will not be sufficiently competitive and the potential buyers will bid prices for generation assets that are likely to be below fair, competitive prices.[15] Furthermore, from the prospective of the utility selling the assets, if its stockholders are not responsible for paying any stranded costs, then it will have no incentive to receive a fair price for each of its generation assets. Remember, the lower the sale price of an asset is, the higher the stranded costs will be, but if the utility knows that its ratepayers will pay 100 percent of these higher stranded costs, it will have no incentive to try to receive a fair price for each of its generation assets.

If the prices at which generation assets are actually sold are below the sale prices that a truly competitive market would yield, then stranded costs will be overestimated, and ratepayers will pay too much in stranded cost recovery charges. At the same time, the new owners of the generation assets would begin selling their output at market prices; they would not sell their output at below-market prices just because they bought the assets at below-market prices. Therefore, in this scenario, consumers would end up paying more than they should in stranded cost charges while not experiencing any compensating reduction in market prices for generation.

It is also important to recognize that the divestiture of generation assets by vertically integrated utilities will not mitigate the potential for *horizontal* market power to be exercised in the future electric generation market *if* all of a utility's generation assets are sold to a single buyer or spun-off into a single entity, or if some of the assets are sold to a company that already owns a significant amount of the region's generating capacity.[16] If the same generating resource mix is still controlled by one company after the sale or spin-off of generation assets, or if the sale results in owners of even larger amounts of generation assets, then this could maintain or even increase market power in the region, and impede the development of a fully competitive generation market. Therefore, before adopting the market valuation approach and instituting the divestiture of generation assets, state regulators should take into consideration the extent to which there is an existing framework to deal with potential future horizontal market power issues in the region. As a preventative measure, state regulators should seriously consider requiring vertically integrated utilities to divest their generation assets into enough *separate* generation companies, such that each one has very little or no market power in relevant generation markets.[17] How many separate companies would be sufficient is not known at the current time.

Another potential disadvantage with the market valuation approach is that a utility's stranded cost results could be affected by: 1) the length of the period during which a certain amount and/or a certain type of the utility's assets are to be sold,[18] 2) how the assets to be sold relate to the amount and types of existing resources serving the region, and 3) the amount and/or types of other utilities' assets that are up for sale. For example, if a utility were required to sell all of its assets at once, or if all of the same type of the utility's assets (e.g., all of the utility's baseload plants) were sold at once, then the regional generation-assets market could be temporarily flooded. The disequilibrium between the supply of assets and the demand for assets could give bidders the bargaining power to negotiate sale prices below the "equilibrium," or competitive market, sale prices. This would lead to greater stranded costs for the utility selling its assets.

To avoid market imperfections that would yield "fire-sale" prices, phased divestiture during a sufficiently long period (e.g., five years) might be a partial solution that state commissions should consider for their state or region. Phased divestiture would moderate the pace of asset sales and allow market participants more time to gather information about the assets.[19] Small, diverse amounts of resources could be offered for sale every few months, for example. Furthermore, if the state commission's review of bidders' prices for a generation asset concluded that none of the bids seem fair, then the utility should not be obliged to sell that asset just for the sake of meeting a time constraint. The commission and the utility should be allowed to delay the sale of an asset if the bid prices seem unfair. Together, these strategies could help to keep the supply and demand for generation assets in equilibrium, and could allow buyers and sellers enough time to gather adequate information about the generation asset market so that they would know what sale prices are fair.

A final disadvantage of the market valuation approach is that it cannot accommodate a true-up mechanism, whereby stranded costs would be adjusted annually to reflect new information about actual prices in the generation market.[20] If the amount of stranded costs were adjusted over time to reflect actual market prices, the risk to ratepayers of paying too much for stranded costs and the risk to generation owners of recovering too little stranded costs would be minimized. Under the market valuation approach, if it were determined at any point after the sale of a generation asset that it had been sold for too much or too little money,[21] a true-up mechanism between the buyer and the seller[22] would not be feasible because the sale price would be actual and final. Even if a public utility commission were to approve a sale price prior to the sale, it is quite possible that the commission would not have enough information about whether or not the price seems reasonable. This scarcity of information would be due to the infancy of the generation assets market. It is the responsibility of the regulators to ensure that ratepayers do not over- or under-pay on stranded cost recovery, but under the market valuation approach, it may not be possible for them to fulfill this responsibility because a true-up mechanism would not be feasible.

The Administrative Valuation Approach

Under the administrative valuation approach, a utility's stranded generation costs would be based on the difference between *projections*[23] of the utility's revenues for electric generation if generation prices were deregulated, and *projections* of the utility's revenues for electric generation if generation prices continued to be regulated based on the utility's embedded costs of generation. More specifically, if an administrative approach were used, stranded costs would be calculated as the net present value[24] of the change in generation-specific revenues that a utility would experience over some specified time period as a result of selling electricity at market prices rather than at regulated prices. A utility's generation-specific revenue requirements would include the fixed and variable costs of generation.

As indicated in Diagram 1, a regulatory commission could use the administrative valuation approach to calculate a utility's stranded costs regardless of whether or not divestiture of the utility's generation assets occurs on a voluntarily basis. In other words, a commission may believe that there are advantages to allowing a utility to divest its generation assets, but may also believe that until a competitive generation asset market develops, the asset sale prices should not be relied upon for the purposes of calculating stranded costs. Because asset sale prices could fluctuate significantly during the years when competition is developing, regulators may prefer to base the initial estimate of a utility's stranded costs on their *own* projections of market prices for generation. Furthermore, regulators could adjust (or "true-up") their initial stranded cost estimate annually to reflect actual market prices as they become known, or they could assume that their estimates will be accurate enough that the stranded cost estimates should be final. Therefore, as delineated in Diagram 1, there are four scenarios under which the administrative approach could occur: 1) utilities choose to divest and the regulators decide to true-up, 2) utilities choose to divest and the regulators decide *not* to true-up, 3) utilities choose *not* to divest and the regulators decide to true-up, and 4) utilities choose *not* to divest and the regulators decide *not* to true-up. These scenarios are

Diagram 1

Approaches to Estimating Stranded Costs

Administrative Valuation	→	Utilities voluntarily divest	→	True-up occurs
Administrative Valuation	→	Utilities voluntarily divest	→	No true-up
Administrative Valuation	→	Utilities choose not to divest	→	True-up occurs
Administrative Valuation	→	Utilities choose not to divest	→	No true-up
Market Valuation	→	Mandatory divestiture	→	No true-up

compared to that for the market valuation approach.

In general, supporters of the administrative approach for computing stranded costs cite five reasons why they prefer this approach over the market valuation approach:

Advantages

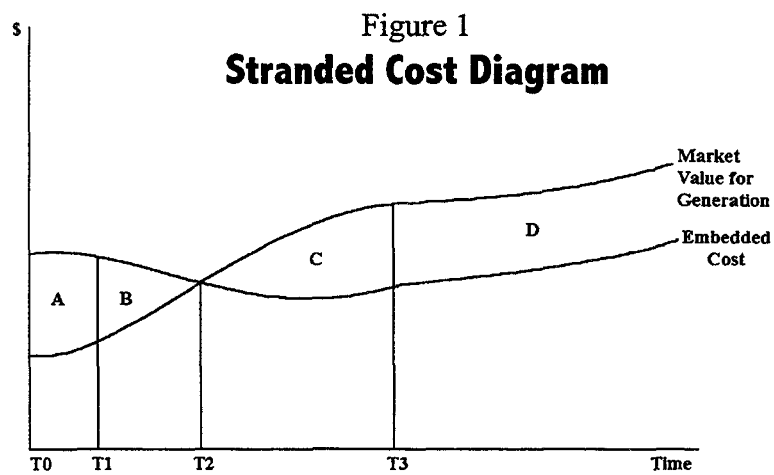
- The approach would calculate stranded costs over a significant length of time (determined by the regulators).
- The approach could accommodate a true-up mechanism.
- If a true-up mechanism were not used, then the calculation of stranded costs would be final.
- The approach does not prohibit a utility from divesting some or all of its generation assets, but it holds ratepayers harmless vis à vis the sale prices of any assets.
- The approach allows for distinguishing between the stranded costs themselves and the financing costs associated with them (i.e., the return on stranded investments) for the purpose of proposing a sharing mechanism.

Disadvantages

- The actual calculation of stranded costs would not be as easy and straightforward as under the market valuation approach.
- The stranded cost results could be strongly affected by the maturity of the competitive power market, if a true-up is not used.

The first advantage listed above relates to an important point, namely that stranded cost estimates can be very sensitive to the time period over which they are calculated. This is true because stranded costs are based on the differences between the estimated embedded costs of generation and the estimated market prices of generation in each year during a specified time period, and these differences are likely to decrease over time. (Please refer to Figure 1.) For example, embedded cost-based generation rates for a given utility may be significantly above the market price of power in the first year of the time period. However, for most utilities, the embedded costs of existing generation service would be expected to decline over time due to depreciation and the fact that any new demand would be met with purchases from the

Figure 1
Stranded Cost Diagram



market at market prices rather than with the construction of new utility-owned plants. Market prices for power, on the other hand, may start low in the first year of the time period dueto excess capacity, but could increase over time due to the tightening of available capacity. Therefore, *in this example*, the gap between embedded cost-based generation rates and market prices for power would narrow each year. In general, the gap would narrow each year, even if market prices for power remained constant or declined (e.g., due to increased competition), as long as estimated embedded cost-based generation rates declined faster than estimated market prices for power.

If this trend continued (i.e., estimated embedded cost-based generation rates continued to decline faster than estimated market prices for power), then at some point embedded cost-based generation rates would fall *below* market prices for power. This would mean that there would be *negative* stranded costs in some of the later years. Therefore, if the stranded cost calculation is done over a reasonably long period, then the *net* stranded costs may be Figure 1 lower than if calculated over a short time period. Thus, in order to provide a fair estimate of net stranded costs, it is essential that the calculation not be limited to a near-term period (such as five years or less). In theory, the time period should reflect the expected lives of the generation assets.

The time-sensitivity issue discussed above also means that for any delay in the start of competition in generation, a utility's net stranded costs could decrease. This fact is recognized in a recent study by Oak Ridge National Laboratory: "For the base case, each one-year delay [in the onset of retail wheeling] reduces the [net present value] of the utility's [stranded costs] by about 18 percent, if the utility is allowed to recover costs for a full 10 years."[25]

Another extremely important advantage of the administrative valuation approach is that it could incorporate a true-up mechanism. Such a mechanism would entail four broad steps:

- first, the commission's estimated market prices for power would be replaced with the actual market prices for power to-date;
- second, the commission's estimated embedded cost-based prices for power would be adjusted to reflect actual fuel cost, operation and maintenance costs, utility cost of capital, etc.;
- third, the utility's revenues for generation under regulated and deregulated generation prices would be recalculated over the same time frame used to make the initial stranded cost estimate; and
- finally, the difference between the two re-calculated revenue streams would be determined in order to obtain a re-estimate of stranded costs.[26]

As explained earlier, if the amount of stranded costs is adjusted on an annual basis to reflect actual market prices for generation and fuel, then the risk to ratepayers of paying too much stranded costs and the risk to generation owners of recovering too little stranded costs are minimized. Of course, if stakeholders were confident about the accuracy of the commission's initial estimate of stranded costs, then a true-up mechanism would not be necessary and the initial estimate of stranded costs could be the final one. However, such a situation is highly unlikely because even a small change in the market price of retail generation services could lead to a significant change in the net present value of a utility's stranded costs.

A true-up mechanism would also protect ratepayers, to some extent, from the negative price effects of an immature competitive power market and/or market power, but would only offer limited protection in the years during stranded cost recovery. An immature competitive generation market and/or market power would clearly impact the *actual* market prices for generation used in a commission's true-up. If market imperfections caused the *actual* market price to be higher than what the true competitive market price should have been, then customers would pay more for generation from the market, even though they would also pay a smaller stranded cost recovery charge. However, this trade-off between market prices and stranded costs would still harm ratepayers to some degree because they would pay 100 percent of the difference between the actual market price and what the true competitive market price should have been. In contrast, if there were no market imperfections and, therefore, the actual market price equaled the true competitive market price, then stranded costs would be higher (relative to the scenario with market imperfections), but ratepayers would pay less than 100 percent of this increase in stranded costs, assuming stranded costs were shared with stockholders. Thus, any increase in the *market price* for generation would be born entirely by ratepayers, whereas any increase in *stranded costs* would be shared by ratepayers and shareholders. This implies that the state regulatory commission must be vigilant to prevent market power from being exercised, both during the period when stranded costs are recovered, as well as after. The ability of generation suppliers to exercise market power under increased competition will greatly depend on the structure of the competitive market, as discussed in Section Two of this report.

Yet another advantage of the administrative valuation approach is that, even though no actual sales of generation assets are required, the approach does not prohibit a utility from selling any of its generation assets. A utility could divest some or all of its generation assets at any point during the stranded cost recovery period, and ratepayers would not have to worry about whether the sale prices were fair and, therefore, whether their share of stranded costs were too high. The amount of stranded costs recovered from ratepayers would still be calculated administratively and (presumably) trued-up annually to account for actual market prices for generation. Thus, their share of stranded costs would be guaranteed to be fair. Ratepayers would be unaffected if a utility voluntarily sold one of its generation assets at a given price in a certain year and realized several years later, based on the market prices in the years following the sale, that the sale price should have been higher. In this case, the uility's stockholders will have "lost," the buyer will have "won," but ratepayers will have been held harmless because the stranded costs recovered from them will not have depended directly on any asset sale prices.

The ability to distinguish between stranded generation costs themselves and the financing costs associated with them (i.e., the return on stranded investments) is important not so much for the purpose of *calculating* stranded costs but for the purpose of allocating, or *sharing*, stranded costs between utility shareholders and ratepayers. This point will be expanded in the section on *Sharing Non-mitigatable Stranded Costs* (page 14).

One disadvantage with the administrative valuation approach is that the actual calculation of stranded costs would not be as straightforward as it probably would be under the market valuation approach. However, a myriad of details associated with the market valuation approach (e.g., carefully designing auctioning or sale procedures, addressing the sale's accounting and tax implications, etc.) would be avoided.

The Role of Unbundling Rates in Estimating Stranded Generation Costs

Both of the methodologies discussed above require knowing what the utility's total (i.e., economic and uneconomic) embedded cost of generation is. This necessitates *unbundling* the utility's current embedded-costs-of-service. Electric service costs should first be unbundled into the following categories: 1) total generation and generation-related (i.e., competitive) ancillary services, 2) transmission and transmission-related (i.e., non-competitive) ancillary services, 3) distribution (including existing DSM), and 4) aggregation/customer services.[27] Then, by using one of the methodologies discussed above, the *economic* generation and generation-related ancillary service costs would be separated from the *uneconomic* (i.e., stranded) generation costs.

An often overlooked, but extremely important consequence of unbundling rates stems from the fact mentioned above, namely that the gap between embedded cost-based generation rates and market prices for power should tend to narrow over time, and that the two price trajectories could cross one another at some point during the stranded cost calculation period. (Refer again to Figure 1.) This would mean that the stranded costs *for each year* in the calculation period would decline, and could even become negative, over time. To "balance out" the larger stranded costs in the earlier years with the smaller (or even negative) stranded costs in the later years, some of the stranded costs from the earlier years should be "shifted" to the later years. When net stranded costs are relatively small, *this "shifting" means that there should be a rate reduction in the earlier years*. This is the overlooked consequence of unbundling rates. In fact, even if the stranded costs in the earlier years were exactly offset by stranded costs in the later years (on a present value basis), such that net stranded costs were *zero*, ratepayers should get a rate reduction when rates are unbundled. It is only when net stranded costs are relatively large and the recovery period is relatively short that ratepayers may not get an immediate rate reduction. (Please refer to *Time Frame for Stranded Cost Recovery* for further discussion of how the recovery charge could be structured.)

The Recommended Methodology for Estimating Stranded Generation Costs

The divestiture of generation assets may reduce *vertical* market power, and the market valuation approach would probably make the calculation of stranded costs relatively straightforward. Nonetheless, from a consumer protection perspective, the divestiture of generation assets is not necessarily the *most accurate*, and thus the *most equitable*, way to determine the assets' worth, and therefore to determine stranded generation costs. Based on the advantages and disadvantages of the two methodologies discussed above, the use of the administrative valuation approach with annual true-ups appears to be the most accurate, and therefore, equitable way to determine stranded generation costs. Furthermore, in order to protect consumers, regulators should address how to prevent *horizontal* market power in a deregulated generation industry *before* divestiture is implemented. These recommendations are designed to ensure the lowest and fairest electricity rates for all ratepayers.

With regard to unbundling, each state regulatory commission should conduct complete new cost-of-service studies for each of the state's regulated utilities in order to accurately unbundle the costs of providing each distinct electric service based on up-to-date data. In this way, the rates for those services that are to remain regulated (i.e., transmission and distribution) will be fair and will not be recovering any costs that are attributable to services that may become unregulated (i.e., generation and aggregation).

Mitigating Stranded Costs

An Overview of Mitigating Stranded Generation Costs

Electric utilities should be required to reduce potentially strandable generation costs as much as possible *before* a state takes any steps toward allowing recovery of stranded costs. The most important actions for a utility to take would be those that bring its embedded cost of generation (including operating costs) closer to the market price for generation.

In general, often-cited "mitigation measures," such as those listed below, fall into one of three, broad categories: (1) cost reduction (or true mitigation); (2) cost shifting; and (3) revenue enhancement through load growth. Thus, not all of the measures listed below truly mitigate, or reduce, stranded costs.

a. improving the economic efficiency and productivity of generation;
b. increasing sales (either off-system or on-system) to utilize excess capacity;
c. selling excess generating capacity;
d. retiring uneconomic generating facilities;
e. auctioning power contract rights;
f. exercising termination or release clauses in existing power contracts, including non-utility generation (NUG) contracts;
g. renegotiating or buying out of power contracts, including NUG contracts, that do not have termination or release clauses;[28]
h. enforcing the Public Utility Regulatory Policy Act's (PURPA's) "light load" provision;[29]
i. restructuring or refinancing existing debt;
j. accelerating depreciation of plant or regulatory assets; and
k. executing voluntary write-downs of excessive generating plant costs.

Categorizing Stranded Cost "Mitigation Measures"

- **Cost reduction**: Cost reduction measures primarily include renegotiation of contracts (g), efficiency and productivity gains (e.g., reduction in overhead expenses) (a), refinancing debt (i), retiring uneconomic facilities (d),[30] selling excess generating capacity (c), and auctioning power contract rights (e). Stranded cost mitigation should focus to the greatest extent possible on cost reduction.

- **Cost shifting**: Measures that result in cost-shifting between utility shareholders and ratepayers, among customer classes, or among electricity services (e.g., deregulated and regulated services) should not be considered "mitigation." Examples of cost shifting are voluntary write-downs (k) and accelerated depreciation schedules (j). Some approaches to shifting stranded costs have the same effect as sharing stranded costs—the former approach is implicit and the latter approach is explicit. Non-mitigatable stranded costs should be calculated first, before sharing approaches are established.
- **Revenue enhancement**: Measures that are based on revenue enhancement through load growth should not be considered "mitigation," either. They do not decrease the amount of a utility's stranded costs, but simply spread them over a larger number of kilowatt-hours. While serving a greater load may decrease the stranded cost wires charge on a cents per kWh basis, load building strategies tend to conflict with policies supporting demand-side management (which reduces sales), and tend to increase environmental impacts.

"Mitigation Measures" in Detail

Some of the options mentioned in (a) through (k) in the Overview above deserve additional discussion beyond that provided in the bullets above.

Option (a), improving the operating efficiency and reducing the operating costs of *generation*, could be an effective measure for mitigating stranded generation costs. However, any cost reductions that could cause system reliability and/or the quality of customer service to suffer in the short-, medium-, or long-term should not be permitted. It is important to understand that improving the operating efficiency and reducing the operating costs of *transmission*, *distribution*, and/or *customer services* would not be an effective measure for mitigating stranded generation costs. Some people may argue that if a utility were to reduce the operating costs for transmission, distribution, and/or customer services relative to its original cost-of-service, and it were able to continue to collect the higher cost of service in its existing rates, then this extra revenue should be used to "mitigate" stranded generation costs until new rates were determined.[31] Contrary to this argument, if the extra revenues from improved operating efficiencies for the transmission, distribution, and/or customer service functions of the utility were used to accelerate the depreciation of generation assets, this would not *mitigate* stranded generation costs at all. One reason is that stranded costs are derived relative to the unbundled component of rates for *generation* only, not relative to the bundled rate that includes generation, transmission, distribution, and customer services. Another reason is that the approach would not *mitigate* stranded costs—it would merely recover the costs sooner from ratepayers through bundled rates rather than later through an unbundled stranded cost recovery charge.

With regard to options (f) and (g), the management of each utility that has non-utility generation (NUG) contracts should review the degree to which each contract is likely to imply above-market prices. Contracts with above-market prices should be either renegotiated or bought out, whenever doing so is likely to save ratepayers money over the life of the contract.

Option (h), utility enforcement of PURPA's "light load" provision for above-market qualifying facility (QF) contracts, allows a utility to reduce the amount of power it takes under a QF contract if its load decreases. By not buying quite so much power at prices above-market, the utility can reduce its stranded costs associated with that contract.

Option (i), restructuring or refinancing existing debt, has been incorporated in restructuring legislation in California and Pennsylvania. In Pennsylvania, for example, new bonds will allow utilities to refinance assets at lower interest rates. These will not be backed by the state treasury, but by the law's pledge to let utilities recover "just and reasonable" stranded costs.[32]

Option (j), the accelerated depreciation of plant or regulatory assets, does not reduce or mitigate stranded costs on a present value basis. This approach either makes ratepayers pay for the assets sooner than they would otherwise, or it makes shareholders pay for the assets by reducing their return on equity. In the latter case, consumer advocates may find accelerated depreciation acceptable—but, again, this is a way of getting stockholders to assume a share of stranded costs rather than a way of mitigating stranded costs. The same arguments are true for the approach where accelerated collection of nuclear decommissioning funds would be used as a possible stranded cost "mitigation" measure.

Option (k), voluntary write-downs, is also not a mitigation measure; it is a form of stranded cost sharing, whereby stockholders assume responsibility for some of the costs. Many consumer advocates encourage the stockholders of electric utilities to take action to write-off at least some of the current uneconomic generation costs against their equity in the companies.

The Recommended Measures for Mitigating Stranded Generation Costs

Stranded cost mitigation measures should focus to the greatest extent possible on cost reduction because cost reduction measures are the only true mitigation measures. Furthermore, these measures typically improve equity and/or economic efficiency, whereas cost shifting and revenue enhancement may not.

Sharing Non-mitigatable Stranded Costs

An Overview of Sharing Non-mitigatable Stranded Generation Costs

It is only in the *long-run* that the potential net economic benefits of competition in the electric generation sector may begin to lower rates for all customers, especially small consumers, relative to a continuation of current regulatory practices. Thus, the extent to which the recovery of stranded generation costs is shared between ratepayers and utility stockholders is *crucial* to lowering rates for all customers in the *short- to medium-run*. From a public policy perspective, the key factor to consider in determining how to share stranded generation costs is, of course, equity.

Arguments against Sharing Non-mitigatable Stranded Generation Costs

Many utilities assert that they are legally entitled to recover 100 percent of their stranded generation costs from ratepayers. They claim that they are entitled to recover the stranded costs that they incurred prior to the advent of competition, since all of their existing commitments stem from past decisions that were made pursuant to historic regulatory and legal principles. Utilities point to a so-called "regulatory compact" to support this claim. They use this term to refer to an *implicit* agreement between regulators and utilities, whereby regulators could oversee and influence the activities of the utility, and, in exchange, the utility was guaranteed an exclusive franchise and recovery of *prudent* costs from ratepayers, including a competitive, risk-adjusted rate-of-return on these investments. Furthermore, given that the Federal Energy Regulatory Commission (FERC) has mandated in Order 888 that 100 percent of legitimate, prudent, and verifiable *wholesale* stranded costs be recovered from wholesale customers, utilities argue that this policy should be transferable to *retail* stranded costs, as well.

Advocates of 100 percent stranded cost recovery argue that "utility shareholders have not been compensated previously in their allowed equity returns for the risk of not being able to recover their investments because of fundamental changes in government policy such as are now contemplated. [Furthermore,] without provision for stranded cost recovery ... there will otherwise be no assurance that the most efficient supplier will prevail ... Allowing customers to avoid paying historic costs will not promote productive efficiency, it will only shift the costs to other customers or to utility shareholders."[33] However, those who hold this view do acknowledge that "[t]here is ... an undeniable conflict between permitting utility companies recovery of their stranded [i.e., uneconomic] costs and allocative efficiency, since it is that recovery that holds prices farther above marginal costs than would be required to secure a going return on efficient investment."[34]

In addition to the "regulatory compact" argument, some utilities are also making the argument in favor of 100 percent stranded cost recovery based on the Takings Clause of the Fifth Amendment to the U.S. Constitution.[35] This clause "prevents [the] destruction of private property rights and values without just compensation to the property owner.... Rules that force utilities to yield [the use of] their wires to third parties will result in a taking [of property] because they will destroy the integrated nature of utility property and the value inherent in the enterprise as a whole.... The U.S. Supreme Court has often stated that an owner is to be put in the same monetary position that he would have occupied had his property not been taken in the first place....[36] [Therefore,] where open access will sever a utility from its customers, just compensation will be correctly calculated as the investment stranded by that severance."[37]

Arguments in Favor of Sharing Non-mitigatable Stranded Generation Costs

Many consumer advocates, large consumers, and economists argue that a "regulatory compact" has never existed, or that, "to the extent that it has existed, the contract has been loosely interpreted."[38] Furthermore, they argue that regulatory principles and legal precedents in most states, when considered in light of the changes taking place in the electric industry, do not support anything close to 100 percent stranded cost recovery from ratepayers. Recovery "of stranded assets is not required by historical precedent regarding the enforcement of the 'regulatory contract.'"[39] For example, in responding to FERC's stranded cost position, the National Association of State Utility Consumer Advocates (NASUCA) stated that FERC's position: "1) squarely contravenes the Federal Power Act's mandate to FERC to protect customers from excessive rates and charges, and 2) directly contradicts existing case law regarding the recovery of prudently incurred costs that have been rendered uneconomic for various reasons."[40] NASUCA stated that "thoughtful consideration of customer interests mandates the rejection of 100 percent recovery" of prudently incurred stranded costs.[41] Furthermore, the advocates pointed out "[t]he Supreme Court has stated that 'the Constitution has not and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces.'"[42] The Court enforced this principle in Duquesne Light Co. v. Barasch[43] when it rejected the argument that the "prudent investment standard" is constitutionally mandated. In short, consumer advocates argue that legal decisions and public policies support fair, not full, stranded cost recovery from ratepayers.

One reason why "fair" should not imply "full" is that many of the uneconomic costs on a utility's system that will become stranded costs under competition are due to bad management decisions and/or poor resource planning practices. Therefore, it is appropriate to first consider *management's discretion* over a utility's actions that caused stranded costs in order to establish who has the responsibility for ultimately paying those costs. Given that the state regulatory commission may have initially approved the recovery of costs that have turned out to be uneconomic, one might assume that the regulators ruled that these costs were prudently incurred. However, prudency approvals should not necessarily protect utilities from later having to write-off portions of their uneconomic costs if they turn out not to be "used and useful." *Prudency does not imply a lack of risk.* Even if the decisions to acquire the generation-related assets were deemed prudent at the time, generally there appears to be ample justification in regulatory theory for sharing the stranded costs between utility stockholders and ratepayers now, given that there *always* has been some risk that management decisions would not turn out to be the most economically efficient. However, whether this type of sharing can actually occur in a given state is matter of state law.

This approach to sharing stranded costs is identical to the "risk-sharing" approach that has been used to prevent full recovery of the uneconomic costs of expensive nuclear and coal plants when they were first considered for inclusion in ratebase approximately ten to fifteen years ago.[44] The sharing of uneconomic costs results from taking a "used and useful" approach to ratemaking, whereby the "usefulness" of an investment (i.e., how economic the investment is) is determined by the cost-effectiveness of the investment when compared to other alternatives available in the market at the time the investment actually came on-line. Therefore, in states where the "used and useful" regulatory policy currently exists, uneconomic costs can be (and have been) removed from rates, independent of restructuring. In states where a used and useful policy does *not* currently exist, it could be adopted either as a stand-alone piece of state legislation or as part of the state's restructuring legislation.

Secondly, some uneconomic costs on a utility's system are due to *unanticipated* changes over the last decade or more in fuel prices, the cost of new generating capacity and other economic parameters over which neither utility management nor ratepayers had any control. These uneconomic costs will become stranded costs due to another fundamental and unanticipated change in the electric utility industry, namely the emergence of competition. Neither the ratepayers nor the utilities directly caused or could control these underlying changes. Thus, if *all* of the uneconomic costs on a utility's system were found to be a result of *unanticipated* changes in economic parameters, then at the time of restructuring when these costs become stranded, a *prima facie* equitable approach would be to allocate 50 percent of them to ratepayers and 50 percent of them to utility shareholders. This fifty-fifty approach to sharing is a recommended *baseline* for allocating stranded costs that exist due to unforeseen causes.

In light of the concept of risk sharing, many consumer advocates recommend that each state regulatory commission consider *on a utility-by-utility basis*: 1) what factors led to the utility's uneconomic costs that will become stranded costs due to competition, and 2) what ratemaking treatment have these uneconomic costs received since their inclusion in the utility's ratebase. With respect to the first point, the state commission should consider factors that might have been significantly under the control of each utility, such as the quality of resource planning practices and/or risk management practices. With respect to the second point, the state commission should give serious consideration to the fact that in *many* cases, ratepayers have been paying their utility for 100 percent of its uneconomic costs *plus* a fair rate-of-return on these uneconomic costs. A regulatory commission should determine how much ratepayers have *already* contributed (on a present value basis) during the last fifteen years or so toward paying off a utility's uneconomic costs. A commission may find that this contribution has been substantial and, hence, that sharing the *remaining* uneconomic costs that will become stranded due to competition is more than generous to the utility, given the commission's obligation to ensure ratepayers pay *just and reasonable* rates. Based on these types of considerations which are specific to each utility, the commission should determine whether stockholders should be held responsible for substantially *more* than 50 percent of the remaining uneconomic costs that will become stranded due to competition. If the fifty-fifty approach to sharing is the baseline for allocating stranded costs that exist due to unforeseen causes, then ratepayers should not *typically* be held responsible for more than

50 percent of stranded generation costs, because there would not likely be any stranded costs that the ratepayers caused directly.[45]

An example of a situation in which ratepayers could be held responsible for more than 50 percent of stranded costs relates to the financial viability of the utility. A regulatory commission might ultimately and justifiably determine that ratepayers should be held responsible for more than 50 percent of stranded costs if a utility's stranded costs are very large, and if assigning too much of them to the utility's shareholders would cause the utility to go bankrupt. Depending on the circumstances, bankruptcy may not be in the best interests of either the utility or its ratepayers. Thus, some consideration must be given to the financial integrity of each utility before a final decision about the appropriate degree of sharing of stranded costs is made.

The Recommended Approach to Sharing Non-mitigatable Stranded Generation Costs

Each state regulatory commission should consider *on a utility-by-utility basis* what factors led to stranded costs that might have been significantly under the control of each utility, and what ratemaking treatment the assets with uneconomic costs have received since their inclusion in the utility's ratebase. Then, the commission should determine whether stockholders should be held responsible for substantially more than 50 percent of stranded costs. The commission would do this by first deciding on the appropriate percentage sharing for each generating asset which contributes to stranded costs, based on both the causes of the stranded costs and the historic ratemaking treatment of each asset. Next, the commission would weight these results together to get an overall systemwide percentage sharing. However, retail ratepayers should not be held responsible for more than 50 percent of a utility's prudent stranded generation costs, unless special considerations are necessary to maintain the financial integrity of the utility, or unless certain stranded costs resulted from state legislation. If thepreferred approach to sharing stranded costs would lead to cash flow problems for the utility, particularly in the early years of stranded cost recovery, then one solution might be to have ratepayers pay for a greater share of stranded costs in these early years and a smaller share of stranded costs in the later years, when cash flow constraints ease up.[46]

Sharing Stranded Costs by Reducing the Return on Stranded Investments

Recall that one of the advantages of the administrative valuation approach is that it allows for distinguishing between the stranded costs themselves and the "financing" costs associated with them (i.e., the return on stranded investments). This distinction allows for the possibility of sharing stranded costs among ratepayers, utility shareholders, and taxpayers[47] by simply permitting the utility to recover the amortized capital investment in the stranded costs, but not to recover the return on this investment. This regulatory mechanism would provide a simple means of sharing non-mitigatable stranded costs. As explained in Table 1 (on page 21), this approach to sharing turns out to be approximately 50 percent/50 percent, depending on the detailed assumptions.

Allocating Ratepayers' Share of Non-mitigatable Stranded Generation Costs among Customer Classes

Once legitimate, non-mitigatable stranded costs are allocated between ratepayers and shareholders, allocating the ratepayers' share of these stranded costs among customer classes could be done by using traditional cost-of-service rate design principles, in particular, cost causation. For example, the economic portion of generation costs could be appropriately allocated to each customer class according to cost causation principles, as embodied in the inter-class cost allocators used in the last rate case.[49] Then, the difference between this allocation of economic generation costs by customer class and the allocation of total generation costs by customer class that occurred in the last rate case would represent a fair allocation of stranded costs to each customer class. The conclusion that this stranded cost alloca-

Table 1

Sample Calculation

The implications of sharing stranded costs by disallowing the return on equity associated with those costs are illustrated by the following example. This example applies to the non-mitigatable stranded costs on a utility's system that are due both to unanticipated changes in economic parameters and to bad management decisions.

Assume that a utility had been earning a 12 percent return on equity (after taxes) and an 8 percent return on debt, and had an equity/debt ratio of 50 percent/50 percent.[48] If the utility were no longer allowed to recover from ratepayers these returns on the equity and debt associated with some portion of the non-mitigatable stranded costs, the utility would still have to pay the bondholders 8 percent on their 50 percent of the portion of stranded costs disallowed from ratebase. This money would come out of stockholders' equity return. Thus, the stockholders would experience a -8.0 percent return on equity (before taxes), or a -5.2 percent return on equity (after taxes), due to paying bondholders on 50 percent of the disallowed stranded costs. On the other 50 percent of the disallowed stranded costs (i.e., the equity portion), stockholders would lose their 12 percent return on equity (after taxes). Thus, the average loss to stockholders would be 8.6 percent (after taxes).

For example, if $200 in non-mitigatable stranded costs were removed from the utility's ratebase in the first year, stockholders would, in theory, lose the equity return of $12 after taxes, and $8 to bondholders. However, the $8 would be paid out of equity so that net income would be $8 less than it would have been otherwise. After taxes, the stockholders would only lose $5.20 to bondholders. Thus, the total loss to equity holders would be $17.20 ($12 + $5.20), or 8.6 percent of $200.

If the non-mitigatable stranded costs disallowed from ratebase were amortized over 10 years, then these conditions would, coincidentally, imply a sharing of these stranded costs of 50 percent, 32 percent, and 18 percent among ratepayers, shareholders, and taxpayers, respectively. Thus, this ratemaking mechanism (a 10-year amortization period with no return) provides a simple means of allocating 50 percent of non-mitigatable stranded costs to ratepayers.

tion would be fair assumes, of course, that the existing rate design reflects an equitable approach to allocating joint and common costs across functions (i.e., generation, transmission, distribution, and other) and among customer classes.

Alternatively, applying the *same* cents per kilowatt-hour stranded cost recovery charge to *all* customer classes would be a simpler way to allocate ratepayers' share of stranded costs among customer classes. The contribution of each customer class to stranded cost recovery would equal the charge (c/kWh) multiplied by the class' usage (kWh). Like the method described in the paragraph above, this method would also be fair to all customers because it is consistent with the common finding that a large fraction of stranded generation costs are associated with uneconomic baseload power, which is used primarily to serve higher load factor customers. Therefore, it would be equitable for *all* customers to contribute the same amount, on a cents per kilowatt-hour basis, to ratepayers' share of stranded costs.

Of these two approaches, the more equitable one would need to be determined on a case-by-case basis. The equity of the utility's rates and rate design would need to be considered in the first approach, where the types of assets and liabilities with which stranded costs are associated would need to be considered and allocated to each customer class.

Stranded Cost Recovery Mechanisms

In states where retail rates are unbundled and retail competition is introduced, the local distribution utility could administer either one of the stranded cost recovery mechanisms discussed below to *all* of the retail customers in its service territory. In order to preserve ratepayer equity, recovery of stranded costs from *all* customers should be a fundamental component of any state restructuring effort.

A Wires Charge

A non-bypassable, nondiscriminatory "wires" charge (cents per kWh) would tie the collection of stranded generation costs to the continued use of transmission or distribution service. Under retail competition, the large majority of customers would still use the local utility's transmission and/or distribution lines, regardless of the customer's power supplier. Purchasing power from a competitive generation source should not impact a retail customer's obligation to pay for stranded costs. The wires charge would not discriminate among any customers in terms of who would pay for stranded costs. Furthermore, the wires charge would not influence which supplier a customer might choose because it would not vary from supplier to supplier.[50] Competing suppliers would be on a level playing field vis à vis the stranded cost charge a customer would face, which means the charge would not have anti-competitive consequences. Thus, a wires charge would be non-bypassable and non-discriminatory, and would guarantee that the local utility would recover its stranded generation costs that were eligible for recovery.

Whether the wires charge is levied at the transmission or distribution level is an important issue. The benefit of putting the charge on distribution service is that it is solely within the jurisdiction of the state regulatory commission. Any charges associated with transmission service are likely to be subject to FERC approval. However, it has been argued that the disadvantage of putting the charge on distribution service is that large commercial/industrial customers who are not connected to the distribution system, but rather who take service at transmission voltage levels, could avoid paying the wires charge. While this may appear problematic, it is likely that the FERC will support state regulatory commissions in imposing stranded cost recovery charges on all retail customers, whether connected to the distribution system or directly to the transmission system. This assumption is based on FERC's statement in Order 888 that it "will give deference to state recommendations regarding rates, terms, and cnditions for retail transmission service as long as state recommendations are consistent with Commission open access policies."[51] State regulators could assess the stranded cost recovery charge at the retail meter of each customer so that even large customers connected directly to the transmission system would pay for stranded costs.

An Exit Fee

An exit fee could be developed as a one-time, lumpsum payment, or as a fixed or variable monthly charge. This stranded cost recovery mechanism is different from a wires charge in that it is not tied to a customer's continued use of the transmission or distribution service offered by the utility seeking to recover its stranded generation costs. Rather, exit fees would, in theory, be charged only to customers who "depart" the utility's system by choosing an alternative supplier of generation services.

One disadvantage with an exit fee structured as a one-time, lumpsum payment is that it could create an insurmountable financial barrier for some customers wishing to purchase power from alternative suppliers other than the utility. In creating a barrier for customers who would like to purchase from the competitive generation market, an exit fee would create a barrier to the development of a fully competitive generation market with numerous suppliers.[52]

Another potential disadvantage of an exit fee, regardless of how it is structured, is that its size would presumably be based on a customer's *past* load, instead of his future load. If two customers had identical loads in the past, but in the future one of the customer's load changes significantly, this would imply a different cents per kWh charge for each customer when he chooses an alternative supplier. It could be argued that this would be discriminatory, and should not be permitted for the sake of customer equity.

An exit fee may only be advantageous under the following circumstances. If a specific customer decided to purchase power from an alternative supplier rather than its local utility, and the utility had installed a physical facility to be used *only* by that specific customer, then the customer should be charged an exit fee in order for the utility to recover the costs associated with that facility. These costs should *not* be recovered from other customers since the installed facility was not used by them.

The Recommended Stranded Generation Cost Recovery Mechanism

In light of the costs and benefits associated with each of the recovery mechanisms discussed above, the use of a non-bypassable, non-discriminatory wires charge is recommended for the recovery of stranded generation costs that are not customer-specific. This recommendation is consistent with the decisions on recovery mechanisms that many states have already made, or have proposed.[53] In the case where a utility installed a physical facility to be used *only* by a specified customer and that customer leaves the utility's system, then it should be charged an exit fee in order for the utility to recover the associated costs.

Stranded Generation Cost Recovery and Declines in Consumer Demand

It is important to consider how the recovery of stranded costs due to retail competition would be affected if consumers reduce their demand for electricity for reasons unrelated to retail competition (e.g., self-generation, conservation, fuel switching, or partial or complete facility closures) or move their facilities or homes to a different local distribution utility's service territory. Historically, there appears to be no regulatory precedent for recovering utility-investments (economic or uneconomic) from a customer when its load that the utility was serving declines for reasons unrelated to retail competition. This appears to be true even if these investments were made so that the utility could serve the customer's load.[54] These circumstances are quite different from situations in which individual or aggregated customers might switch to another supplier as a result of retail competition.[55] In this latter instance, all customers, regardless of their supplier, would be responsible for some portion of the utility's stranded investments.

If a utility's stranded costs are recovered from ratepayers via a wires charge (cents per kWh) that is applied by the local distribution company, and if a customer reduces its kWh demand for any reason *other than* retail competition, there is probably no legal opportunity for the utility to collect this "lost stranded cost recovery" from that customer. The customer would only pay the stranded cost recovery charge on each kilowatt-hour that would actually be delivered to that customer over the local transmission/distribution system. Any "lost stranded cost recovery" due to customer reductions in demand would be implicitly allocated to all customers being served by the local transmission/distribution system in the next true-up by increasing the stranded cost charge. Additional stranded costs could be recovered from a specific customer whose load has decreased for reasons other than retail competition *if* that customer had signed a contract with the utility *obligating* the customer to maintain a specified load level. In this case, the contract would be binding and the customer would be responsible for paying the wires charge on the load specified in the contract, as well as for paying any other costs specified in the contract.

In summary, if a utility has stranded costs under retail competition, then all customers, regardless of their supplier, should be responsible for some portion of the utility's stranded investments that are not customer-specific. This responsibility should be met through a wires charge. However, to the extent that customers lowered their demand for kilowatt-hours delivered to them over the local distribution system, these customers would contribute less to stranded cost recovery than they would have otherwise. Even though these customers would not bypass, or avoid paying, the recovery charge on a per kWh basis, they would bypass some stranded cost recovery on an absolute dollar basis.

Time Frame for Stranded Cost Recovery

An Overview on Determining the Time Frame for Stranded Generation Cost Recovery From Ratepayers

The time frame for stranded generation cost recovery from ratepayers should be determined prior to commencing the recovery process. Assuming that a wires charge (cents / kWh) would be used for recovery, a preferred time frame for recovery would depend on: 1) the net present value of the utility's stranded costs that need to be recovered from ratepayers, 2) the estimated level of electricity demand on the utility's distribution system in future years, 3) the utility's discount rate, and 4) keeping the stranded cost recovery charge "reasonable," namely one that would not increase a customer's total electric rate relative to that which the customer is currently paying under regulation. All else being equal, the longer the period allowed for recovery, the smaller the charge (c/kWh) would be. As a consequence, a longer recovery period could allow for greater rate reductions in the early years of the recovery period. However, one disadvantage to this approach is that the longer the recovery period, the longer onsumers would have to wait before they could begin to enjoy the full potential savings from a competitive generation market.

The time value of money should also be considered in determining an appropriate stranded cost recovery period. If the recovery charge remains constant in nominal dollars during the recovery period (e.g., like a fixed mortgage payment), then the present value of the unit charges collected in the later years will be worth less than the present value of the unit charges collected in the early years. However, a stranded cost recovery charge could be set to be constant in real dollars, and then adjusted for inflation each year. This would give greater rate reductions in the early years and account for a portion of the time value of money.

The Recommended Time Frame for Stranded Generation Cost Recovery

The recommended time frame for recovering a maximum of 50 percent of stranded costs from ratepayers is one to ten years. Ten years should be the maximum recovery period, even for utilities with extremely high stranded costs. Furthermore, the recovery charge should be designed to be constant in real dollars, thereby lowering near-term rates. In short, the recovery period, the recovery mechanism, and the amount of sharing should be structured so that in the early years of the recovery period, retail ratepayers enjoy a rate reduction of at least 10 percent, if possible. However, if stranded costs are quite small, then a 10 percent rate reduction may not be possible based on sharing their recovery between ratepayers and stockholders.

Section Two

Market Structures *in the* Electric Industry

Introduction

Why Should Consumers Be Concerned about Market Structure?

The way in which the electricity industry is ultimately structured under increased competition will very likely impact the market prices for generation and other competitive services. Specifically, the amount of generation sold under bilateral contracts versus through some form of a power exchange, as well as the amount of authority granted to Independent System Operators (ISOs), will determine the extent to which there is customer negotiating power, supplier market power, and economically efficient generation dispatch given transmission constraints. These factors will, in turn, play a key role in determining the prices of generation and generation-related ancillary services. Recall from Section One that market prices for generation are an *essential component* in the calculations of stranded generation costs. In short, all electricity consumers will be affected by market prices both directly (i.e., what they pay for generation and related services) and indirectly (i.e., what they pay in stranded generation costs). Therefore, each and every consumer should be concerned about the future structure of the electricity market.

The conclusion drawn in this Section Ones that the preferred market structure is one in which: 1) generation and related services would be supplied solely under bilateral contracts between customers and suppliers, and 2) an ISO would dispatch all bilateral contracts and power plants within the control area strictly on an economic (i.e., variable cost) basis.

An Overview of Wholesale and Retail Competition

The Existing Electric Industry

Historically, most electric generation has been provided to retail customers from power plants owned by vertically integrated utilities that built just enough generating capacity to serve the load in their monopoly service territory and cover required reserves. In addition, vertically integrated utilities have had the option of purchasing wholesale power from neighboring utilities on either a short-term economy basis or a longer-term bilateral contract basis. Short-term economy purchases provide utilities with inexpensive energy when it is available, but these purchases are not coupled to firm capacity. Under a longer-term bilateral contract, both capacity and energy can be purchased on a firm basis.

After the Public Utility Regulatory Policy Act (PURPA) became law in 1978, utilities began to purchase more wholesale power from small power producers, most of whom initially were qualifying facilities (QFs) under PURPA. Generally, these purchases were for long-term capacity and energy (baseload power). The prices of these QF contracts were set by the state Public Service Commissions (PSCs) at forecasted levels of long-run avoided costs (LRAC), such that retail customers of the utilities would, in theory, be indifferent as to whether QF capacity was purchased or whether the utility built its own generating capacity. Unfortunately, the prices of these QF contracts have generally turned out to be above the forecasted LRAC and, therefore, have contributed to stranded generation costs. In the late 1980s, a significant amount of non-utility generation (NUGs) was built that did not qualify as QFs. At this point, utilities began to purchase NUG power on a long-term firm basis, as well. The prices set forth inthose NUG contracts have also tended to be above the current market price for wholesale generation and, thus, have contributed further to stranded costs.

In several regions of the country, power pools were established during the 1970s to help make the provision of power more economically efficient. This efficiency is achieved by allowing several utilities to share their resources to minimize the generation costs for all of them. For example, in New York State, the New York Power Pool (NYPP) was established. It soon became a "tight" power pool, in that a central dispatcher determined when and how much power each plant in the State would produce in order to satisfy the combined load of all eight utilities in the State. In a tight power pool, each plant is dispatched solely on the basis of its short-term variable costs, most of which are fuel costs. The central dispatcher also dispatches any bilateral contracts that are "dispatchable" (i.e., the power under contract can be called upon on an as-needed basis). If some power plants and/or bilateral contracts are "non-dispatchable," then the dispatcher accommodates these constraints by making them "must-run" power supplies. In short, in a tight power pool, each utility first tries to meet its own load with the cheapest power from its own resources, and then the dispatcher automatically meets the utility's remaining load with the cheapest economy purchases from other resources in the pool that are not being used by their owner in that hour. By jointly dispatching all power sources, a tight power pool provides the least-cost (i.e., the mathematically optimal) way of using all power supplies and transmission lines in the pool so that all of the pool's ratepayers can benefit to the maximum extent possible.

Thus, in some states, there has been a significant degree of wholesale competition for many years among new wholesale power suppliers and existing utilities that own power plants. However, until FERC's open access transmission order (Order No. 888) is fully implemented, most observers would probably agree that the wholesale market for power is still not fully competitive, and that there are some improvements to be made in the way wholesale markets (including transmission pricing) are structured. In part, the wholesale market is still not fully competitive because the price of power from most generating plants is regulated by the state PSC as part of bundled retail rates. Because of this, the competitive market is currently restricted to a minority of all power supplies, where even the price of QF power and power from independent power producers (IPPs) is based on long-term contract rates approved by the Commission rather than on market-based rates. Presumably, the greater the fraction of the generation mrket that is deregulated (in terms of price) and allowed to compete, the greater the degree of competition there will be.

The Future Electric Industry

In addition to moving toward greater wholesale competition, many customer groups and regulatory commissions in states throughout the country have been investigating how to move toward retail competition. The essence of retail competition is that each customer will be able to buy its generation, generation-related services, and aggregator services from a market comprised of many sellers. The customer will no longer be limited to buying these services from the monopoly provider (i.e., the local utility). The customer will, however, still be limited to buying regulated transmission and distribution service from monopoly providers.

It is important to be clear that all electric generation could be *deregulated* within an industry structure where there would be *no* retail competition, but where there would only be full-scale wholesale competition. In other words, retail competition requires that there be a deregulated generation market, but a deregulated generation market could exist without retail competition. This means that retail competition and its potential impacts on electricity markets should not be confused with the deregulation of generation and its potential impacts on electricity markets.

For the portion of the generation market that is (or will be) deregulated, and for aggregation services, some industry restructuring advocates support a market structure that is completely dependent upon *bilateral contracts*. In the extreme case, the power flows from these contracts would be scheduled by the buyers, and an independent transmission system operator (ISO) would be needed merely to coordinate all of the contract flows and to re-schedule them when conflicts arise. A tight power pool would not be necessary or desirable, in their view, and would interfere with customer choice. Other restructuring advocates support a more complicated market structure, whereby a *poolco* would be established as a competitive short-term energy market (i.e., a spot market), and bilateral contracts would be used to lock into fixed prices for short-, medium-, and long-term power purchases. In this way, a customer could:

- sign contracts for power so that he would know ahead of time what prices he would have to pay (i.e., he would be ensured price stability and predictability);
- buy power from the poolco, whereby he would have to pay the poolco's market clearing price in each hour; or
- purchase power through a mix of contract purchases and spot market purchases.

A poolco would be fundamentally different from a "tight" power pool, such as the NYPP, in terms of the basis for dispatching generation. The poolco would not perform a variable cost-based dispatch. Rather, each supplier would submit bids to the poolco in hourly increments for generation that the supplier could make available. The bids would be based on the *total price* that the supplier would be willing to accept to cover both variable and fixed costs. Generation would be dispatched by the poolco from lowest to highest bid until total demand was met. The highest bid generation that was used to meet total demand in that hour would determine the *market clearing price*. This price would be paid to each and every owner of dispatched generation, regardless of the type of generation (i.e., baseload, cycling, or peaking), and regardless of the price at which the generation was actually bid. This approach to pricing is an *extremely* important feature of a poolco.

There is also a lively, on-going debate as to whether bilateral contracts should have to be dispatched through the poolco, whereby *"contracts for differences"* (i.e., differences between the market clearing price and the contract price) would be necessary to ensure that all power under contract was sold at the contract price. Alternatively, bilateral contracts could all be dispatched first, and then the remaining demand could be met by the poolco.[56]

Furthermore, there is discussion over whether a poolco or some other market mechanism should be used to establish location-specific prices for transmission in order to take transmission system constraints into account via "congestion cost pricing." Presumably, by doing so, potential users of the transmission system would be given the "correct" price signals so that the transmission system would be used most efficiently. However, such approaches are highly controversial.[57]

As discussed in the following sections, it appears that it would be very easy for generation owners to exercise market power in a poolco, whereas it would not be as easy in a bilateral contract market. But in a poolco that allows for bilateral contracts, the ability of generation owners to abuse market power could be somewhat mitigated. However, if the market clearing prices that emerge from the poolco imply extra profits for generation owners relative to those they could earn under bilateral contracts, then generation owners might prefer to bid most of their generation into the poolco, rather than sell it under bilateral contracts. This would only serve to enhance market power.

A Bilateral Contract Market

Advantages and Disadvantages of Bilateral Contract Markets

This discussion begins with some of the advantages of a bilateral contract market. One advantage is that being able to sign contracts of all possible durations should help potential builders and/or owners of new generating capacity, as well as new aggregators, enter the market. Assured revenues from sales under each contract would allow the builder/owner to finance construction of generating capacity, and would allow aggregators to do further marketing and establish a customer base. Being able to sign contracts of all possible durations could also allow buyers to exercise negotiating power. For example, they could negotiate contracts with fixed prices in order to ensure price stability and predictability. Some consumers may prefer fixed prices for the purposes of budgeting (either personal or business).

Of course, signing a commitment for power supplies for a given period of time could mean that a consumer might end up paying too much or too little relative to where the market price ends up during this period of time.[58] This potential deviation from market prices over the contract duration is seen by some as a negative aspect of relying solely on a bilateral contract market. However, this risk could be mitigated by each buyer having a mix of short-term, medium-term, and long-term contracts. Furthermore, buyers could purchase hedging contracts. Finally, bilateral contracts would provide buyers and sellers with the opportunity to negotiate any kind of special arrangements they desire. Because each contract's parameters could be specified to meet the detailed needs of the buyer, bilateral contracts could lower costs for those customers with negotiating power or special needs.

The above cited advantages and disadvantages of bilateral contracts are generally accepted. However, another major advantage of a bilateral contract market that may be more controversial is the view that it could offer customers better protection from the abuse of horizontal market power that could potentially be exercised by the owners of generating facilities than a poolco-based market structure could offer. One argument underlying this claim is that because a bilateral market is inherently based on many buyers and sellers all *negotiating contracts confidentially*, there is no over-arching market mechanism that will automatically determine the prices that buyers will pay for generation and related services. Other arguments supporting this claim appear in the next section.

A Poolco-Based Market

Given the above-cited advantages of a bilateral contract market, and the fact cited earlier that tight power pools could be used to dispatch bilateral contracts in order to produce the lowest-cost dispatch, one might wonder why *poolcos* have been proposed. In order to understand better what issues are at stake in the debates between poolco advocates and critics, it is important to understand how a competitive bilateral contract market for electricity would compare to a "pure" poolco-based market. A "pure" poolco is one in which there are no bilateral contracts. While this is an extreme case, comparing a pure poolco market with a pure bilateral contract market will help clarify some important distinctions between the two.

A Bilateral Contract Market Compared to a "Pure" Poolco

In many markets for commercial and industrial products, buyers sign bilateral contracts with sellers at various times for different amounts of a given product to be delivered at various times in the future. In a perfectly competitive market, if the product is completely uniform (i.e., each unit of the product is identical to every other unit), the price of the product at any given time should only vary due to the set of specified contract terms. For example, the unit price might vary due to the number of units bought, the amount of lead-time until the first delivery date, the schedule of deliveries, etc. However, the price under identical contract terms entered into by different sellers and buyers should be almost identical in a competitive market.

In a competitive bilateral contract market like this, each buyer signs a set of contracts to purchase a given product under a range of delivery dates. To minimize risk, some contracts are short-term (e.g., deliveries may range over only a few months or years), and some are long-term (e.g., deliveries may range over many years). Thus, in any given month, a buyer takes delivery of the product based on his set of contracts, each of which could have different unit prices for the product. The lower the average price for deliveries in any given month, the better-off the buyer is. The important point here is that since different buyers purchase a product through different mixes of contracts, each buyer likely sees a different average price relative to what other buyers see in any given month.

At any given delivery time, then, there is not a single market clearing price, or a single marginal cost, even in a fully competitive market. The single market clearing price or marginal cost exists only at the time contacts with the identical specifications are signed.

In contrast to the more typical competitive bilateral contract market described above, a pure poolco would provide a market structure which, in essence, would collapse the contract-signing time and the delivery time into the *same* point in time. The contract terms would be the prices and quantities bid by suppliers into the poolco. Bids would be made in hourly increments, and until the total electricity demand for that hour were known (i.e., until deliveries of electricity had been made), the market clearing price for electricity in that hour would not be known. Furthermore, as stated earlier, the market clearing price for electricity in any given hour would be based on the highest priced bid that was accepted in that hour in order to meet demand. All suppliers whose bids were accepted would be paid the same market clearing price for their generation that was dispatched. This is quite different, then, from many other markets where wholesale customers typically pay different prices for the same product delivered at the same time.

Another key difference worth highlighting is the fact that in a pure poolco a buyer could not take the time to hunt around for the best deals when s/he was interested in lining up electricity purchases for a given hour, nor could a buyer negotiate the lowest price by playing one seller off against another. The "contract price" would simply be defined by the highest priced amount of generation bid into the poolco that was required to meet total demand in each hour.

Electricity is also somewhat of a unique commodity in that electricity buyers' ability to influence their own aggregate demand from hour to hour is very limited -- there is little dispatchable load control or load management technology built into the supply/demand system for electricity. Therefore, in a pure poolco, if the prices in certain hours were typically higher than most buyers would be willing to pay, these buyers could not suddenly decide to buy less, or no, electricity for delivery in those hours. Yet, in markets for other types of goods, if the prices offered are higher than buyers want to pay, then they can often wait to buy the product for significant periods of time, or at least until they have a chance to try to negotiate with several suppliers to see if they can bring the selling price down.

One way in which prices can often be moderated in typical competitive markets is for the buyer to commit to buying under a long-term contract. Often the price for a product under a long-term contract with a particular delivery date is less than the price under a short-term contract for the same delivery date, though occasionally the reverse can be true. In addition, in a typical market, committing to buy more of a product can sometimes reduce the per unit cost. This will depend on whether the aggregate level of demand is at a point where the marginal cost of producing more of a product is lower or higher than the last unit produced. These types of factors can be weighed by buyers prior to making their purchasing decisions in typical competitive markets. Again, a pure poolco is different. By definition, the marginal cost of supply in a pure poolco always increases with increasing demand, so the buyer can *never* lower his per unit cost by buying more electricity.

Furthermore, in many typical competitive markets, buyers can moderate their demand for a product if the price gets too high by switching to a *substitute product*. Electricity, in contrast, has no substitute for most of its end uses, and switching to another energy form, where possible, often requires significant lead-time and/or making a major capital investment. Thus, if fuel switching does occur, it occurs slowly and fairly infrequently for any given customer. In a poolco-based market, there would be very little flexibility for buyers, and at least in the short-run, electricity consumers would be completely at the mercy of the suppliers' bids submitted to the pure poolco.

A final point is that most other products can be stored in larger proportions of total demand than electricity can be. The ability to store a product means that supply and demand are more likely to stay in equilibrium, and therefore prices are not as apt to be subject to extreme volatility or to the abuse of market power.

To summarize, even though a poolco would provide a highly visible market price, it is not clear how much benefit consumers would get from knowing the market clearing price hour by hour *after the fact*. In addition, even though a poolco would provide a mechanism for all sellers and buyers of generation without contracts to participate in the market, very short-term contracts could also be arranged in a bilateral contract market, with the added benefit that owners of baseload plants would not be paid prices for peaking generation, as would routinely happen in a poolco. Thus, the abuse of market power in short-term bilateral contract markets would appear to be much more difficult to exercise, and would have more limited price impacts, than in the much more highly constrained, rigid, and deterministic market structure of a poolco.

The Potential for Leveraging in a Pure Poolco[59]

The simple pricing structure of a pure poolco relative to other market structures and the fact that all transactions would be short-term would likely make it much easier for generation owners to game their bids in order to exercise market power through what Tellus Institute calls "leveraging." (This concept is explained below.) Furthermore, both in the near-term and in the long-term, a poolco might be limited to a relatively small number of owners (e.g., less than ten) each owning a mix of baseload, cycling, and peaking capacity, and together owning the vast majority of generation capacity in any given regional poolco. (This is how most states and regions are currently organized.)

Even more importantly, the number of owners of existing generating units that could realistically be expected to represent the marginal unit of supply in periods of moderate or high demand might be smaller still, since many units would already be running and thus could not contend to be the marginal unit. New potential suppliers would only enter the market if the average market price that they would likely receive after bidding their new capacity into a poolco were above the fixed and variable costs of providing this new capacity—it would not be profitable for them to do so otherwise. Therefore, once a certain set of power plants exists, there may not be any new market entrants in the short term that might drive down the market clearing price in any given hour. It might take years for the poolco prices to rise high enough for owners of new generation, particularly owners of new baseload generation, to enter the market. However, in a typical market with bilateral contracts, new market entrants can partcipate at any time as long as they are able to sign financially sensible medium- and long-term contracts for their output that would allow them to recover their costs and make a fair return on their investment.

In theory, in a perfectly competitive poolco (where generating capacity would come in very small increments), a seller would always bid just a little above its variable costs, since the next highest cost seller along the supply curve would have variable costs only slightly higher than the first. If the first seller bid much *above* its variable cost of production, its bid might not be accepted by the poolco if the output of the next seller's plant was sufficient to complete the need to meet total demand. Also, the difference between the variable cost of each generating unit dispatched and the market clearing price would be used to cover suppliers' fixed costs (including a fair profit). In fact, the sum of these differences over time would determine the value of each plant. Of course, the supplier of the *marginal* generation in a given hour would, by definition, have set the market clearing price based on its bid, and, thus, in that hour there would be little difference between the market clearing price and the variable cost of that supplier's marginal plant, and little fixed cost recovery for that plant in that hour.

In practice, however, there are many other reasons why sellers would want, and would be able, to bid more than "just a little" above their variable costs in actual pure poolco operations. First of all, power plants in a utility system do not have continuously varying variable costs. There are gaps in cost between the plants along the supply curve. This means that to the extent to which sellers could learn the shape of the supply curve by tracking poolco operations, a seller could bid its plant at a price just below the next highest cost unit. Sellers could learn the shape of the supply curve during the pure poolco's early stages of operation by varying their bids in an attempt to search out the curve's shape.

Secondly, near times of peak demand, sellers would necessarily have to bid their peaking capacity above variable cost in order to recover their fixed costs. In a poolco, owners of peaking units (especially owners of *new* peaking units) would need to recover a large portion of the fixed costs of these units during peak periods because, by definition, this type of unit does not run nearly as often as other types of generating units do in a typical year. Given that peaking units are dispatched so few hours in a year, the price differential between the true variable cost of each peaking unit and the market clearing price would need to be large enough such that the last few peaking units dispatched in any given peak hour could collect sufficient revenues during the year to cover *all* of their annualized fixed costs. This price differential could easily be as high as ten cents per kWh,[60] or more, even on a real levelized basis.

In fact, on average, generation prices bid into a poolco would be highly *unlikely* to equal bidders' variable costs at *most* levels of demand (most hours of the year), not just during hours defining peak demand. One reason is that if a supplier believed that its unit was likely to be "on the margin" (namely, the unit to supply the last amount of generation dispatched to meet total demand) in a given hour, there would almost never be an incentive for that supplier to bid just the variable cost of the prospective marginal unit because doing so would produce absolutely no contribution to that unit's fixed costs, and certainly no profit, if that supplier's generation did indeed end up being on the margin. Thus, if suppliers believed they were likely to set the market clearing price, they would naturally try to get away with bidding a little higher than their variable cost, while still succeeding at being dispatched. An owner would do this at each and every demand level (i.e., in each and every hour) for his prospective marginal plants, *regardless* of how many or how few of his *other* plants had already been dispatched. Through trial and error, suppliers would determine how high a bid they could get away with in any given hour, versus the chance of not being dispatched, in order to maximize their fixed cost recovery for each individual marginal plant. While this tendency would serve to raise average market clearing prices in a pure poolco, the price increase would not likely be a big effect due to these considerations alone. The bigger effect of this bidding practice by owners of marginal units would be that ***all*** **owners of generation units that were dispatched in a given hour would receive *extra* profits[61] because of the bidding behavior of owners of generation units near the margin**. "Leveraging" refers to this ability to earn extra profits on plants already dispatched by exercising market power on the margin of the poolco dispatch.

Thus, the third reason why sellers would want, and be able, to bid above their variable costs is due to a strong "leveraging" effect that exists in poolcos. **A *critical* aspect of poolcos is that the owner of a marginal unit that was bid above variable cost and set the market clearing price would earn additional profits *both* on his marginal unit and on any of his units that he bid at a *lower price*, and therefore that would be dispatched prior to the marginal unit**. In fact, if an owner had many units that he had bid at lower prices, he would have an even greater incentive to raise his bid for the prospective marginal unit quite high because the risk of that unit not being dispatched, and the risk of not recovering some of the fixed costs associated with that prospective *marginal* unit, would be lower than the pay-off in extra profits paid to all of his *non-marginal* units if the prospective marginal unit were dispatched at the higher bid and set the market clearing price. Hence, **this effect would be especially likely for generation owners who own a wide range of *different types* of generating units (i.e., baseload, cycling, and peaking)**. If a generation owner owned units which were well distributed across the supply cost curve, then the owner could try to exercise this high-price bidding strategy at almost any demand level and impact the market clearing price in most hours during the year. Because baseload, cycling, and peaking units basically represent generation in different markets, leveraging allows for the exercise of market power in one market (e.g., peaking) to influence the price of power in another market (e.g., baseload) in a very deterministic way.

A generation owner could also exercise market power through leveraging by *with-*

holding some of his generation from the poolco's bidding process. If an owner withheld some of his generating capacity, then the poolco operator would need to accept higher and higher bids for generation (i.e., it would need to go up higher on the supply bid curve) in order to meet demand. If the resulting increase in the market clearing price, relative to what it would have been if the owner had *not* withheld some of his generation, were large enough, then the extra profits that the owner would earn on his capacity that he bid and that was dispatched would more than offset the profits that the owner would lose by withholding some of his capacity.

As an example, let's first assume that an owner bids all of his capacity (1,000 MW) at its true variable cost of 4 cents/kWh, and that the market clearing price he is paid is 6 cents/kWh. His profit would be $20,000 in one hour (6 cents/kWh less 4 cents/kWh, times 1,000 MW). Now let's assume that the owner only bids 900 MW of his capacity. In order to still earn a profit of $20,000, the market clearing price must be at least 6.2 cents/kWh (6.2 cents/kWh less 4 cents/kWh, times 900 MW = $20,000). Therefore, in this case, if the owner can predict that the market clearing will likely increase by more than 0.2 cents/kWh when he withholds 100 MW of his capacity, then he will do this in order to earn higher profits. Thus, this approach to manipulating the market clearing price, namely by withholding some generating capacity from the poolco's bidding process, is another way in which owners could exercise leveraging in a pure poolco.

Finally, in a poolco, market power may also be exercised through *systematic tacit collusion*, "defined as a situation where competitors are able to predict each other's pricing and production behavior based on past activity and the underlying fundamentals involved in the industry."[62] As mentioned earlier, within a geographic region, the actual number of owners of a significant number of power plants is currently relatively small, and the number of owners of generating units that could realistically be expected to represent the marginal unit of supply in periods of moderate or high demand is smaller still. Furthermore, leveraging benefits all owners of generation simultaneously. Given those conditions and the hourly bidding activity required in the poolco model, it would be possible for "competing" suppliers to observe each other's operating and bidding practices quite closely and with relatively high levels of predictability at each demand level of the year. Without any overt supplier interaction, the result would be strategic bidding, or the artificial raising of prices across all generation bids, by suppliers who see it in their mutual self-interest to raise their bid prices. This is more likely to occur in a poolco than in a bilateral contract market because of the stronger leveraging effect that exists in a poolco.

In summary, the exercise of market power in a pure poolco would not be qualitatively different from its exercise in a typical market with bilateral contracts, but because a pure poolco would be completely deterministic in terms of the market clearing price once the bids were submitted, it would be a much less flexible market structure, and thus a much easier one for suppliers to game. Without bilateral contracts, the inability of buyers to contract ahead of time for power at a given price also would mean that new market entrants to a pure poolco would have to invest in a power plant based solely on their "guesstimates" of what the market clearing prices in the poolco would be in the future, once they could get a new plant on-line. Of course, by then, the existing plant owners could alter their bidding strategies, effectively moderating their exercise of market power, in order to keep new entrants out of the poolco market for as long as possible. Thus, a new market entrant would probably not risk entering poolco market until the economics appeared favorable based on the most conservative and cautious assumption that suppliers would bid only their variable costs, except during a relatively few peak hours.

End Notes

1. The different categories of stranded generation costs are discussed further on the following pages.

2. Hirst, E., Hadley, S., and Baxter, L. *Factors that Affect Electric-Utility Stranded Commitments*. Oak Ridge National Laboratory. Oak Ridge, Tennessee. July 1996: page 1.

3. This does not exclude the possibility that some uneconomic costs associated with certain generating units were written-off in the past.

4. When utilities write-off stranded costs or otherwise suffer a financial loss, this reduces the utilities' federal and state income taxes, resulting in a sharing of those costs between the utility shareholders and taxpayers. To the extent that taxpayers and electricity ratepayers are the same households or businesses, they will contribute to stranded cost recovery through two mechanisms.

5. Note, however, that the rate at which ratepayers pay for stranded costs over time could be lowered in the near-term in order to lower rates, even under 100 percent stranded cost recovery.

6. The market price of a generation asset would tend to reflect a private discount rate (the rate at which the value of money changes over time). Relative to regulated utility discount rates, private discount rates are higher. Higher discount rates would mean that the "value" of a generation asset to private investors in the market would be lower than the "value" of the asset to a utility and its ratepayers under regulation. Therefore, the switch away from regulation and its use of a regulated utility discount rate to a competitive market and its use of a private discount rate in itself creates some stranded generation costs.

7. Lesser and Ainspan. "Using Markets to Value Stranded Costs." *The Electricity Journal*, October 1996; page 69.

8. Market power refers to the ability of one or more suppliers to charge consumers a price for a good or service that is above the price that would be offered in a fully competitive market.

9. Though the actual stranded cost calculation would be relatively straightforward, setting up the appropriate procedures for auctioning or spinning-off the generation assets would not be straightforward, nor would sorting out the federal and state tax implications.

10. The electric transmission and distribution sectors will remain regulated under restructuring, and thus market power should not be a problem in these sectors.

11. Refer to: Frankena, Mark. "FERC Must Fix Its Electric Utility Merger Policy." *The Electricity Journal*. Volume 9, Number 8.: pages 32 and 43.

12. For additional information on this topic, refer to Dr. Richard A. Rosen's direct testimony in FERC Docket EC96-10-000, and in the Maryland PSC Docket 8725. Both dockets pertain to the Baltimore Gas & Electric Company and the Potomac Electric Power Company proposed merger.

13. In a settlement agreement filed October 1, 1996 with the Massachusetts Department of Public Utilities, New England Electric System (NEES) agreed to sell all of its generating assets in return for full recovery of stranded costs. ("NEES Agrees to Sell Generating Assets in Return for Stranded-Cost Recovery," *Electric Utility Week*, October 7, 1996: pages 1 and 8-9.) Furthermore, in Connecticut, "the utility's cooperation in market valuation of its assets and divestiture of its generation assets" is one of four factors that "must be used by the DPUC [Department of Public Utility Control] in determining ... whether stranded cost recovery is allowed and the extent and timing of such recovery." (*The Connecticut Choice Plan for Electric Industry Restructuring*, Proposed by OCC, OAG, ENRON, CLF, CIEC, CRRA, CCC. August 8, 1996: page 17.)

14. Proponents of the market valuation approach argue that it "can work well even when there are not well-defined markets for the assets in

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question." (Lesser and Ainspan. "Using Markets to Value Stranded Costs." *The Electricity Journal*, October 1996; page 67.)

15. It is important to note that fair market prices for existing generation units will always be below those for new generation units, which will be more efficient and have longer lives.

16. For example, New England Electric System (NEES) "hopes to find one buyer for [its] entire fossil-fuel/hydro package." "If no bids prove acceptable to the utility, it has the option of spinning-off 100 percent of its generating assets into a separate company." ("NEES Agrees to Sell Generating Assets in Return for Stranded-Cost Recovery," *Electric Utility Week*, October 7, 1996: page 8.)

17. The conventional method for assessing the potential degree of horizontal market power in a particular market resulting from a merger is based on the traditional antitrust approach employed by the Department of Justice (DOJ) and the Federal Trade Commission (FTC). This approach, which usually involves the application of the Herfindahl-Hirschman Index (HHI) test, measures the market concentration in an appropriately defined product and geographic market. However, the HHI may not be appropriate for the electric industry. (Refer to the "Direct Testimony on Market Power of Dr. Richard A. Rosen," EM-96-149, November 26, 1996.)

18. "A divestiture occurring over too short a period of time might reduce the value of the assets or deprive the utilities of the time to form well conceived plans concerning the structure, sequence and timing of divestiture. For these reasons, this Plan suggests that utilities should complete their divestiture within five years from the initial date on which retail choice is allowed." (*The Connecticut Choice Plan for Electric Industry Restructuring*, Proposed by OCC, OAG, ENRON, CLF, CIEC, CRRA, CCC. August 8, 1996: page 19.)

19. In no market do the buyers and the sellers have perfect information, especially in the first few years of a developing market. Phased divestiture would allow market participants more time to gather information.

20. Proponents of the market valuation approach argue that it can be combined with "'insurance' that can be purchased voluntarily by individual consumers to reduce their risk of overpaying stranded generating costs fixed by today's market value of generating assets in the future, should those market values increase over time. This insurance, which is already used in real-time pricing contracts, can hedge risks to consumers more efficiently than ongoing administrative 'corrections' to stranded-cost valuation." (Lesser and Ainspan. "Using Markets to Value Stranded Costs." *The Electricity Journal*, October 1996; page 67.) However, this insurance would cost extra and might not be practical for small volume customers. The need for such insurance could potentially be reduced by phasing divestiture in over time.

21. In a perfect market, the sale price of each generation asset would reflect each buyer's estimates of the future costs (expenditures) and benefits (income streams) of running the plant. If these estimates turned out to be inaccurate, then this would imply that the sale price was either too low or too high.

22. In this case, the seller would be the utility and its ratepayers.

23. These projections could be made, or at the very least, reviewed, by the utility's regulatory commission.

24. The present value is the value of a cost or a stream of yearly costs that have been discounted to reflect the fact that future benefits or expenditures are worth less than current benefits or expenditures.

25. Hirst, E., Hadley, S., and Baxter, L. *Factors that Affect Electric-Utility Stranded Commitments*. Oak Ridge National Laboratory. Oak Ridge, Tennessee. July 1996: page 19.

End Notes

26. In the event that these steps are interpreted by law to be retroactive ratemaking, the appropriate laws should be changed to allow true-ups.

27. It will not be obvious how all of the costs, for example administrative and general ("A&G") costs, should be categorized. However, costs that pose this challenge should not merely be allocated to the transmission and distribution (i.e., regulated) categories because this would allow the utility's shareholders to avoid paying their share of some potentially stranded generation costs, and would be anti-competitive vis à vis other generation owners.

28. Options (c) through (g) all depend on how the value to the utility of the power source differs from the value to potential buyers of the power source.

29. PURPA's "light load" provision for above market qualifying facility (QF) contracts allows a utility to reduce the amount of power it takes under a QF contract if its load decreases.

30. "Uneconomic" facilities, in this case, are those that cannot operate at market price. For example, nuclear plants that require major capital additions will likely not be competitive in the market, and therefore should be shut down.

31. The extra revenues could also be used to support a higher return to stockholders.

32. "PA. Lawmakers Pass Competition Bill That Phases in Choice in 1999-2001." *Electric Utility Week*, December 2, 1996: page 9.

33. Baumol, Joskow, and Kahn. *The Challenge for Federal and State Regulators: Transition from Regulation to Efficient Competition in Electric Power*. December 9, 1994: pages 3-4.

34. Baumol, Joskow, and Kahn. *The Challenge for Federal and State Regulators: Transition from Regulation to Efficient Competition in Electric Power*. December 9, 1994: page 41.

35. Rowe, J., and Graening, P. "Property Law: It's Physical - and Logical." *The Electricity Journal*. August/September 1996: page 45-51.

36. See, for example, U.S. vs. Miller, 317 U.S. 369, 373 (1943); U.S. vs. Reynolds, 397 U.S. 14, 16 (1970).

37. Rowe, J., and Graening, P. "Property Law: It's Physical - and Logical." *The Electricity Journal*. August/September 1996: pages 45, 49, 50.

38. Hartman, R. and Tabors, R. "The Regulatory Contract and Restructuring: A Modest Proposal." *The Electricity Journal*, December 1996: page 79.

39. Hartman, R. and Tabors, R. "The Regulatory Contract and Restructuring: A Modest Proposal." *The Electricity Journal*, December 1996: page 79.

40. Docket No.RM94-07-001. Comments dated August 7, 1995: page 2.

41. Docket No.RM94-07-001. Comments dated August 7, 1995: page 5.

42. 488 U.S. 299 (1989).

43. Docket No.RM94-07-001. Comments dated August 7, 1995: page 4.

44. In the *New England Power Company (NEPCO)*, 688F.2d 1327 (D.C. Cir. 1981), the prudently incurred plant investment was abandoned because changing circumstances rendered the investment uneconomic. The FERC's ratemaking treatment provided for a ten-year amortization of the plant investment, with no return on the unamortized balance. The *NEPCO* precedent demonstrates that the "regulatory compact" does not require full cost recovery.

45. An exception to this guideline could occur if certain stranded costs came about due to legislation.

End Notes

46. Sometimes bond indenture requirements can lead to cash flow problems well before bankruptcy even becomes an issue.

47. It is important to realize that when utilities write-off stranded costs or otherwise suffer a financial loss, this reduces the utilities' federal and state income taxes, resulting in a sharing of those costs between the utility shareholders and taxpayers. To the extent that taxpayers and electricity ratepayers are the same households or businesses, they will contribute to stranded cost recovery through two mechanisms.

48. This example also assumes a 10 percent utility discount rate and a 35 percent income tax rate.

49. Note that the economic portion of generation costs would only be allocated prior to retail competition. After retail competition starts, the "market" (i.e., competitive suppliers) will offer various rate structures for generation.

50. "Recovery of stranded costs can be compatible with efficient competition if the recovery mechanism is properly structured, so that the outcome of competition between rival suppliers will be determined on the basis of which is truly the more efficient. In order to accomplish this, the costs of historical commitments must be assessed in a non-discriminatory manner against all competing suppliers, including the incumbent utility." (Baumol, Joskow, and Kahn. *The Challenge for Federal and State Regulators: Transition from Regulation to Efficient Competition in Electric Power*. December 9, 1994: page 4.)

51. FERC's Fact Sheet on Order 888, April, 1996: p.4.

52. Hempling, Scott et al. *The Regulatory Treatment of Embedded Costs Exceeding Market Prices: Transition to a Competitive Electric Generation Market.* National Regulatory Research Institute. November 7, 1994.

53. Such states include California, Massachusetts, Nevada, New Hampshire, New York, and Pennsylvania.

54. There is one recent state commission order that conflicts with the apparent regulatory precedent. To facilitate the bypass of Cambridge Electric Light Company ("Cambridge"), on May 14, 1994, the Massachusetts Institute of Technology ("MIT") filed a petition with the Massachusetts Department of Public Utilities ("DPU") to establish rates for service from Cambridge required in connection with the operation of an MIT cogeneration facility. On September 23, 1995, the DPU issued an order that established the requested rates and ordered that MIT pay Cambridge an exit fee. This issue is still being litigated.

55. One of FERC's standards for allowing a utility to recover wholesale stranded generation costs due to competition is that of "reasonable expectation." If it can be proved that when a given utility-investment was made, it was reasonable at that time for the utility to expect that it would continue to serve the now-departing wholesale customer, then the utility can collect an exit fee from the now-departing customer.

56. There are many complexities underlying this debate, but they are beyond the scope of this paper.

57. Here too, there are many complexities underlying this debate, but they are beyond the scope of this paper.

58. This risk would be minimized if the contract price were somehow indexed to the market price, but then market power and its influence over price comes back into the picture.

59. For a more extensive discussion of the potential market power problems with poolcos, refer to: Tellus Institute. "'Leveraging' - The Key To The Exercise of Market Power in a Poolco." November, 1996. It is important to add that since the time when the paper was written, Tellus Institute has developed a mathematical proof that leveraging will exist as a stable (equilibrium) bidding strategy of each generation owner, and that competitive pressures will *not* force each owner' bids down towards variable cost only.

End Notes

60. For example, $0.10 / kWh = (0.1 real levelized fixed charge factor * $300/kW new peaking capacity) / (300 hours per year).

61. By "extra" profits, we mean the incremental income that all owners would enjoy on all of their dispatched units when the market clearing price is well above the variable cost of the marginal unit, as opposed to only slightly above the variable cost of the marginal unit.

62. *The Future of Wisconsin's Electric Power Industry—Environmental Impacts Statement, Volume I.* Docket 05-EI-114. Wisconsin Public Service Commission Staff, Electric Division, October 1995: page 239.

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