Among customer classes, there are significant differences in the cost elements discussed above, leading to differences in cost of service. Many of the industrial and certain commercial and institutional customers (hospitals, large office buildings and schools, etc.) tend to purchase larger volumes of electricity, purchase it at higher voltage levels on the transmission/distribution system and tend to exhibit smaller variations in power requirements on a daily and a seasonal basis,[28] as compared to residential or smaller commercial customers. These variations in size, voltage level and load factor give rise to differences in the cost of serving the various customer classes. These kinds of cost differences are typically reflected in the rates and can be observed in the resulting revenues collected from the various customer classes.[29] A set of fairly typical relationships might be as indicated in the following table:

Table IX - 1

Representative Revenue per Kilowatthour (cents per kilowatthour)

Description	Residential	Commercial	Industrial
Generation Revenue	5.0	4.5	4.0
Transmission and Distribution Revenues	3.0	2.5	1.0
Total Revenues	8.0	7.0	5.0

[28] Customers who use power on a relatively consistent basis are called high load factor customers, while customers whose usage tends to vary significantly from daytime to nighttime, from weekday to weekend, and from season to season are called low load factor customers.

[29] These differences in cost are generally reflected in rates, but, because factors others than costs (including disagreements about the definition of costs) enter into the ratemaking equation, the differences in rates do not precisely equal the differences in costs.

The differences in average revenue per kilowatthour for generation, transmission and distribution and in total reflect variations in the cost to serve these types of customers.

The above describes what is collected in current rates, where the embedded or book costs of the utility are the basis for establishing the rates. With a competitive environment, the generation component would be priced on a competitive market basis. For purposes of illustration, assume that the market price of generation currently is such that when differences in load factor and voltage level are taken into account, the average price is 3.0¢/kWh for residential customers, 2.7¢/kWh for commercial customers and 2.5¢/kWh for industrial customers. We would then have the situation depicted in the following table:

Table IX - 2

Illustrative Comparison Between Embedded Costs and Market Prices (cents per kilowatthour)

Description	Residential	Commercial	Industrial
Embedded Generation Cost	5.0	4.5	4.0
Market Generation Cost	3.0	2.7	2.5
Difference	2.0	1.8	1.5

To extend the example, assume now for simplicity that the mix of customer classes is such that the values for the commercial class represent the weighted average values. That is, the system-wide average value for generation is 4.5¢/kWh on an embedded basis, and 2.7¢/kWh on a market basis.[30] Assume now that, at least initially, the amount of

[30] A different assumption about the mix of customer classes could be made, but it would just complicate the example without adding to its illustrative value.

Stranded Cost Collection (SCC) is equal to 100% of the difference between book value and market value. On an unbundled basis, customers would pay the embedded T&D charge, the market value of generation, and an SCC equal to the difference between the embedded cost of generation and the market value of generation.

One approach to the allocation of the SCC would be to charge each class the difference between the embedded costs and the market price of generation as determined above. In this particular example, the end result would be that each customer class would continue to pay the same rate that it was paying previously. No customer class would pay less, and no customer class would pay more, and there would not be any shifting of cost recovery among customer classes, or between customers within classes. If a lower amount of SCC is to be collected, a proportional relationship (i.e., 80%) for all classes could be established to avoid cost shifting. In terms of rate design, the SCC would be collected through the demand and energy charges of the rates that have both, and through the energy charge for those rates which collect both demand and energy costs through an energy charge.

Since rates are not always precisely aligned with costs, a second approach would be to adjust the existing rate schedules to match cost of service before allocating stranded cost recovery. Assume for purposes of illustration, and for simplicity, that an adjustment to cost of service would require a 0.2¢/kWh increase in the generation component of the residential rate and a 0.2¢/kWh decrease in the generation component of the industrial rate.[31] Residential customers would now pay 3.0¢/kWh for T&D, 3.0¢/kWh for the market

[31] Or vice-versa.

value of generation and 2.2¢/kWh for SCC, for a total of 8.2¢/kWh. Industrial customers would pay 4.8¢/kWh and commercial customers would continue to pay 7.0¢/kWh. While arguably more precise, the result of this approach is some shifting of cost recovery between classes. The rate design would be the same as in the immediately preceding discussion.

A third approach sometimes mentioned is collection of the SCC on a uniform amount per kilowatthour basis. In our example, this would imply 1.8¢/kWh from all customer classes. While admittedly simple, the per kilowatthour approach to collection does not necessarily recognize the existing differences in cost of service already reflected in the rates charged to the different customer classes, or differences in existing rate structures. It also produces shifts in revenue collection among customer classes and between customers within each class, just as in the preceding example.

A fourth approach is suggested by those economists who argue that the SCC is really designed to recover sunk costs, and therefore the recovery mechanism should not be sensitive to customer consumption levels, but instead, should be in the nature of a fixed charge which does not vary with the level of the customers' purchases. This leads to the idea that the SCC could be imposed on a per customer basis (or other fixed basis–such as a demand charge), either uniformly across all customer classes, or on a basis which varies by customer class to recognize differences in size. Whatever the form, the imposition of SCC charges on a per customer basis will result in the shifting of cost recovery relative to current tariffs.

B. Basis of Application

The second level of consideration for stranded cost recovery is the basis of application. In the early days of the discussion of open access, many commenters referred to a concept of "exit fees," which would be charges applied to customers who decided to choose an alternate generation supplier. The concept of exit fees implied that customers who did not elect alternate suppliers, but instead stayed with their incumbent utilities, were not paying anything toward stranded cost recovery.

On further consideration, it became clear that customers who continued to purchase from the incumbent utility at regulated rates were in fact paying rates that contributed to the recovery of stranded costs, because the tariff rates were above market prices. Accordingly, the discussions have shifted toward the concept of a "non-bypassable" wires charge, paid both by customers who elect to continue to purchase from their incumbent utility, as well as by customers who elect to purchase from an alternate electric utility supplier. This is a much more accurate description of the process, and recognizes that *stranded cost recovery is implicit in the tariff even if an alternate supplier is not selected.*

Within each customer class, a cost-based approach would recover the non-bypassable charge based on some combination of demand charges and energy charges applied to the customers' level of electricity usage. The theoretically economic approach, which is designed to not distort consumption decisions, would apply the collection mechanism within each class on some form of customer or other fixed charge basis.

Customer consumption levels can and will change over time for a variety of reasons. A residential customer may add a room in his or her house, may install an air conditioner or other electricity-using appliance, may experience a reduction in use because children move out, may experience a reduction in electricity purchases because of the installation of solar panels or other renewable energy resources, may upgrade insulation, buy a more efficient air conditioner, etc. In addition, year-to-year variations will occur because of changes in weather and economic factors. Commercial and industrial customers may experience changes in consumption levels as a result of a variety of factors, such as weather and economic cycles, as well as the addition of new facilities or the closing of old facilities. Purchased electricity requirements may also change as a result of the installation of solar panels, fuel cells, distributed generation, or even larger scale cogeneration facilities.

The question relevant to stranded cost recovery is the level of consumption to which the SCC charges should be applied. Some would argue that it should apply to historic consumption levels because the generation facilities for which SCC recovery is permitted were, it is argued, built to serve historic consumption. This logic also would argue for exempting new load and new customers from any payment of SCC, since the facilities giving rise to SCC, according to this theory, were not built to serve these new loads. This approach raises substantial equity questions, particularly in situations where an existing industry installing generation facilities would be required to pay SCC on historic usage, but a new competitor located in the service territory would be completely exempted from any SCC charges.

An argument for applying SCCs to current consumption only is that all customers have always been required to support the cost of the system as it exists, in proportion to their current consumption (unless they have contracted for a different arrangement), and that vintage pricing which treats customers differently depending upon when they attach to the system has never been implemented. Another argument is that many of the factors which cause a change in consumption have nothing to do with the opportunity to utilize the incumbent utility's transmission and distribution lines in order to purchase power from another electric utility. For example, economic downturns and the right to increase or decrease the level of consumption because of a change in factory output are circumstances that have always existed, and the right to choose a different electricity supplier should not affect how these changes translate into power cost. Also frequently cited is the fact that customers have always had the opportunity to install cogeneration, renewable resources and other on-site generation resources, and that there is nothing about customer choice of an off-site electricity supplier that has affected these customer options.

C. Conclusion

There are strongly held views of all sides of both dimensions of the collection issue. In deciding what is appropriate, consideration should be given to a number of factors, including the potential impact of cost-shifting between and among customers and customer classes, adherence to cost of service principles, the impact on the development of alternative resources, impacts on the use of energy efficiency measures, and the effect on economic development.

MISSOURI PUBLIC SERVICE COMMISSION
STRANDED COST WORKING GROUP
MUNICIPAL ELECTRIC UTILITIES

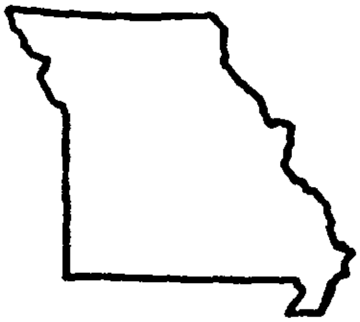
Municipal Electric Utilities have provided electric service in Missouri for well over one hundred (100) years. Eighty-nine (89) Missouri public power systems serve nearly three quarters (3/4) of a million people, approximately fifteen percent (15%) of the state's population. Municipals vary in size from slightly over 100 meters to slightly less than 90,000 meters.

Thirty-five (35) of the eighty-nine (89) utilities generate some electricity, with only six generating more than 3000 MWH per year and only two generating more than 100,000 MWH per year. Municipals account for approximately five percent (5%) of the state's total generation in a typical year.

Missouri's municipal electric utilities are owned by the municipalities in which they serve. For the entire history of public power in our state, we have had local ownership and local control. Policy is established and rates and conditions of service are approved in open forums at public hearings under Missouri's Sunshine Law. In all states that have adopted restructuring legislation, the regulation of municipal electric utilities has been left at the same level of government that it resided at prior to restructuring. If the regulation of municipal utilities was at the local level prior to restructuring, as is the case in Missouri, it was left at the local level after restructuring.

Who pays, the customer or the owner, is a primary question when stranded cost recovery is discussed for investor-owned utilities. For municipal utilities the customers are, in effect, the owners of the system. Customers will pay as customers or as owners. The only real concern is that all members of a class pay their fair share of any stranded costs.

Most of the eighty-nine (89) municipal electric utilities in Missouri will have little or no stranded costs that will need to be considered. For those limited cases where stranded costs exist, it is suggested that the authority for determining the amount and the method of recovery be left at the local level.



ELECTRIC POWER IN MISSOURI

GENERATION TRANSMISSION DISTRIBUTION

Because of our enviable industry position, it is important that any plan advanced to change the current structure be carefully examined from a CONSUMER point of view. Any retail wheeling plans asking to change the present electric utility system should include appropriate consumer safeguards if advanced as viable alternatives.

OUR PRESENT SYSTEM: VALUABLE CONSUMER FEATURES WORTH PRESERVING

From the perspective of consumers in high cost states, Missouri users of electric power hold an enviable position. Under our present system consumers have access to abundant low cost electric power and benefit greatly from the extraordinary reliability of our generation, transmission and distribution systems.

System reliability is achieved through an integrated transmission system jointly owned and operated by the Missouri investor-owned, consumer owned, publicly-owned and Federally owned utilities. This unique partnership results in huge consumer savings and maximizes system reliability.

Through bilateral agreements of electric power generators in our state and region, utilities come to the aid of one another during emergency power plant shut downs and transmission outages. As a result of this arrangement, Missouri consumers receive continuity of electric service under the most extreme conditions. A percentage of our states generating capacity is set aside under contract to achieve this high industry standard.

Industry safety programs for those receiving electrical service and the safety of the general public meet the highest standards in the nation. Those who work on energized high voltage electrical power systems receive specialized training for the protection of themselves, their fellow workers, consumers and the general public.

Prepared by —
Missouri's 47 consumer-owned electric utilities serving more than 500,000 consumers.

CONSUMER SAFEGUARDS

DEREGULATION

Through existing regulation by the Missouri Public Service Commission and through member and public ownership, Missouri electric utilities are OBLIGATED to sell their low cost electric power to Missouri consumers.

Under any deregulation plan, investor-owned utilities, electric cooperatives and municipal electric utilities should remain obligated to provide Missouri consumers first choice of low-cost electric power generated in our state.

RELIABILITY

Under any deregulation plan, the guidelines for obligating "spinning reserve generation" would follow those established by state or regional power pools. Participation in these reliability pools by all Missouri energy providers should be mandatory.

SAFETY

To ensure safety for utility staff and consumers, electric distribution companies, electric cooperatives and municipal utilities should be required to exclusively own and service electric distribution facilities including required metering equipment. Any other approach would place utility personnel and the general public at risk from actions of unqualified persons working on the electrical delivery system.

The distribution systems should be required to meet or exceed those safety standards set by the Missouri Public Service Commission and/or the National Electrical Safety Code.

Restructuring

Presently an electric utility company, electric cooperative or municipal electric utility may combine electric power generation, transmission and distribution functions within one corporate entity.

Any retail wheeling plan should require the corporate separation of electric power generation, transmission and distribution including metering to clearly identify the costs of "unbundled" electric service. Such a segregated corporate structure will allow the retail consumer to clearly identify and compare prices quoted by electricity marketers and competing electric utilities under competitive market conditions.

Retail Wheeling

Proponents of retail wheeling promise lower electric rates for all consumers and to all user classes. Individual residential users, farmers, small business owners, and difficult to serve consumers must benefit equally through any state retail wheeling plan.

Under any retail wheeling plan, we must adopt a "universal service plan" to ensure that inner city and rural consumers alike would be guaranteed safe, reliable and equitable electric service.

Stranded Costs

Under any retail wheeling plan, stranded cost recovery for electric power generation, [if allowed], should be paid for by the stockholders and/or the customer base of individual investor-owned utilities; the owners and members of electric cooperatives and the owners and consumers of municipal electric utilities. Consumers should not be required to share in stranded costs of systems they presently do not receive service from. The authority to identify stranded costs and the approval of a recovery schedule should be the responsibility of existing regulatory authority.

A formula for stranded cost recovery resulting from a large load leaving a distribution system should be established. [Some of these costs may be imbedded in a cooperatively owned transmission system]. The costs for investment recovery by the distribution system would be imposed on the vacating customer when and if it could be clearly shown that such a circumstance would result in higher electricity costs to incumbent distribution systems. The responsibility of identifying stranded distribution costs and the approval of a recovery schedule should be the responsibility of existing regulatory authority.

Service Standards

Under any retail wheeling plan, the Missouri Public Service Commission should regulate marketing companies to insure consumer rights. Marketing companies should be required to operate so as to give Missouri Electric consumers the benefits of Public Service Commission consumer protection rules.

Marketing companies should be required to pay the incumbent utility a service continuity fee to insure uninterrupted service to consumers. The fee to be paid by the marketing company would be established by the Missouri Public Service Commission.

When a marketing company or competing electric utility supplier discontinues service to a customer for nonpayment, the incumbent utility should be given the right to charge a three month deposit based on the customers previous three month usage. Such an arrangement would discourage intended abuse of the system by those who would take advantage of open competition to the detriment and added costs of incumbent consumers.

If marketing companies are allowed to do business in our state from an office in New York, California, Texas or any other state, strict bonding requirements should be required to insure their financial integrity for the protection of Missouri consumers. Marketing companies incorporated in Missouri should meet the same strict bonding requirements.

Foreign based marketing companies or those incorporated in Missouri should be required to meet the same financial and service standards as any other electric utility operating in our state under state, federal and/or municipal law.

Very specific law should be enacted to require marketing companies to honor promises they make to Missouri consumers. If they are allowed to sell electricity, an essential service, consumers will need protection to insure marketers deliver long term, fixed cost service as incumbent suppliers are required to do.

Marketing and Consumer Education

Under any retail wheeling plan, all sales promotion plans to compete for retail customers in our state should be submitted to the Missouri Public Service Commission for review and approval.

Approval would be based on the advertising piece achieving a clear and simple sales message easily understood by the consuming public. The total costs of retail electric service, including taxes, should be presented in such a manner as to make it easy for the average consumer to make simple cost comparisons of competing plans.

Telemarketing for retail electric service should be strictly regulated for five years or for a longer period of time if the Public Service Commission determines it is in the best interest of the consumer to do so. Because explicit cost details would be required by those soliciting retail electric customers, telemarketing would truly be an annoyance until a certain level of public understanding could be achieved through consumer education.

Building New Generation

Through "utility responsibility" all segments of the electric utility industry are required to deliver short and long term electric power needs to their consumers. Under this unique service obligation, utilities must comply with specific "plant siting" laws and meet strict tests of "convenience and necessity" to locate, construct and operate electric power generating plants in our state. Long term planning responsibility and condemnation authority accompany this obligation.

In a deregulated climate, some electric utilities may no longer have the obligation to build new generating plants. The question of who will build new power plants and what accompanying authority they might need will have to be addressed.

Consumers of electricity will need assurances that investments in new plant will be made on a timely basis to meet their long and short term needs.

LEGISLATIVE ACTION

ELECTRIC POWER IN MISSOURI

Our Present System:

Valuable Consumer Features Worth Preserving

PROPONENTS OF RETAIL WHEELING PROMISE LOWER ELECTRIC RATES FOR ALL CONSUMERS. BEFORE OUR STATE LEGISLATURE ACTS, LET'S MAKE SURE THAT IS A PROMISE WE CAN KEEP.

AS MISSOURI CONSUMERS PRESENTLY ENJOY LOW RATES AND HIGH SERVICE RELIABILITY, THERE IS NO LEGISLATIVE PRESSURE TO ENACT NEW LAW QUICKLY.

THERE IS NO THREAT FROM WASHINGTON, D. C. TO ACT IN HASTE. THE CONGRESS IS STRONGLY INCLINED TO ALLOW INDIVIDUAL STATES TO ADDRESS THE RETAIL WHEELING ISSUE. IN ADDITION, THOSE BILLS BEING CONSIDERED AT THE FEDERAL LEVEL DO NOT CALL FOR STATE ACTION UNTIL THE YEAR 2002 OR BEYOND .

MISSOURI CONSUMERS WILL BENEFIT BECAUSE WE CAN LEARN FROM THOSE STATES THAT RUSHED INTO RETAILING WHEELING. WHEN THEIR STATE PLANS BECOME FULLY OPERATIONAL, THE RESULTING EFFECT ON RATES, RELIABILITY AND SAFETY WILL NO LONGER BE PURE CONJECTURE. OUR STATE PLAN CAN BE ENHANCED BECAUSE OF WHAT WE MAY LEARN FROM ACTUAL OPERATIONAL EXPERIENCE. MISSOURI CONSUMERS WILL BENEFIT MOST IF OUR LEGISLATORS PROCEED WITH DELIBERATE CAUTION IN SHAPING STATE POLICY ON RETAIL WHEELING.

Appendix C

Decisions in Other Jurisdictions

This Appendix briefly outlines the main features of stranded cost recovery decisions in key states that have addressed this issue.

CALIFORNIA

Stranded cost recovery will be granted for above market costs associated with generating assets, nuclear plant settlements, purchased power contracts and regulatory obligations (including nuclear decommissioning.) Costs associated with retraining and early retirement of employees will also be considered as recoverable transition costs. Recovery of these costs was deemed appropriate due to past regulatory policies and past Commission decisions that have created many of these costs. The stranded costs will be collected through a non-bypassable end-user surcharge (competitive transition charge), calculated as a percentage of the dollar amount of each customer bill. The CTC will be allocated to all customer classes in the same approximate proportion that similar costs are being recovered as of June 1996. Any shortfall in recovery from industrial and large commercial customer classes will not be charged to residential and small commercial classes, or vice versa. Utilities generally will not be allowed to recover stranded costs past 2001, though exceptions are granted for long-term contracts and certain other types of potential stranded costs.

Market methods of calculation are to be employed as much as possible, with administrative methods used up to the point in which the market method can be put in place. Prior to market valuation, stranded costs are to be calculated annually. All generation plants must be measured against the market within five years for stranded cost valuation purposes. Market methods include sale or spin-off of assets, as well as use of appraisals by independent third parties.

Divestiture of generating assets is encouraged. The general rule is that the return on equity to be applied to stranded cost assets is to be 90% of the utility's cost of debt. The 10% discount will be eliminated if the utility divests at least 50% of its generating assets. A further 10 basis point increase in ROE will be given to utilities for every additional 10% increase in the amount of generating plants disposed of through sale or spin-off. Utilities can retain 10% of the savings associated with renegotiation of long-term contracts. A utility's accumulated deferred income tax balance will be offset against its stranded cost amount.

Securitization of stranded costs is allowed if such financing will benefit residential and small commercial customers through rate reductions. Securitization bonds will continue to be paid off in full after 2001, notwithstanding any other restrictions on the timing of stranded cost collection.

Companies are not guaranteed full recovery of their stranded costs. The lower risk associated with assets for which stranded cost recovery is granted justifies a lower return on equity. Rates (including fuel adjustment) are frozen and utilities are at risk for recovery of allowed balances. The portion of stranded cost recovery to be securitized will provide for a 10% rate reduction in 1998. Further, it is the intent of the Legislature that a cumulative rate reduction of 20% be applied by 2002, not counting competitively procured generation costs and securitization costs.

Source: CPUC Decision 95-12-063, December 20, 1995, as modified by Decision 96-01-009, January 10, 1996; Assembly Bill 1890, signed September 1996.

ILLINOIS

Stranded cost recovery in the form of a "transition charge" will be allowed. The legislation states that Illinois has an interest in providing utilities the opportunity to earn a return on investments made pursuant to traditional regulation. Recovery of stranded costs will be allowed through 2006, though an extension to 2008 can be considered by the Commission based on these four factors: the need to maintain the financial integrity of the utility, the prudence of the utility's actions to reduce costs, the ability of the utility to provide reliable service, and the impact on competition.

The method for calculating the transition charge will be a "lost revenues" approach, based on the average level of revenues received from the departing customer over the previous three years. The "lost revenues" calculation will be offset by the amount of revenue for delivery services received from the customer, the market value of the foregone power formerly used by the customer, and a "mitigation factor" that is a surrogate for new revenue sources and cost efficiencies that utilities should try to achieve in a competitive environment. The mitigation factor will be calculated at between 6-10% of residential customers' bills over a period of time for residential customers (different percentages are to be used for other customer classes).

The market value of power component of the transition cost calculations will be determined through reliance on electricity price indices, or if such indices are not available, by review of a "neutral fact finder." The neutral fact finder will be a member of the public accounting industry, and will make an annual report to the Illinois Commission as to their findings. A new neutral fact finder will be selected every year.

Securitization will be allowed up to 50% of a utility's capitalization, but 80% of securitization proceeds must be used to refinance debt or repurchase equity, with the remainder available for other purposes, such as retiring fuel obligations, including spent nuclear fuel.

Rate reductions of between 2% to 15% are mandated, depending upon the particular utility and their current rate levels.

Source: Amended House Bill 362, "Electric Service Transition and Customer Choice," signed December 1997.

MAINE

Utilities should be given a reasonable opportunity to recover legitimate, verifiable and unmitigatable stranded costs, but not a better (or worse) opportunity than that offered under traditional regulation. Principles similar to the "regulatory compact" have long been recognized in Maine court decisions. Recoverable categories of stranded costs are generating assets, long-term contracts and regulatory assets. Nuclear decommissioning costs are not part of stranded costs, but will continue to be collected through transmission and distribution rates. Stranded cost amounts will also be collected through transmission and distribution rates, not through exit fees.

Retail access for all customers is to be in place by March 2000. Prior to that time, the Commission will establish interim estimates of stranded costs. In 2003 and every three years thereafter, the Commission will correct substantial inaccuracies in the stranded cost calculations, but on a prospective basis only. An asset-based calculation method is to be used, not one based on lost revenues. Market information is to be used to the greatest extent possible, including, but not limited to, valuations from sale of generating assets and rights to power under contract.

By March 2000, each investor-owned utility is required to divest its generating assets, except for nuclear facilities, contracts with Qualified Facilities, facilities outside the U.S., and facilities necessary for operation as a transmission and distribution utility. After January 2009, the Commission may require divestiture of the Maine Yankee nuclear unit. After February 2000, the utilities are also to sell capacity and energy rights associated with long-term contracts that were not divested earlier. Utilities can seek extensions for the divestiture requirement, if it can be demonstrated that the sale value of assets are likely to improve as a result of the extension.

Utilities are to use all reasonable mitigation methods to reduce stranded costs, and are to assume a reasonable level of mitigation in estimating stranded costs. Incentives to mitigate stranded costs include possible use of price caps and sharing of savings associated with mitigation efforts. The Commission may consider the level of a utility's mitigation efforts in making its stranded cost recovery findings.

While there is no legal requirement that utilities recover 100% of stranded costs, the Commission does not find any justification to "share" stranded costs between shareholders and ratepayers, as all such costs have been judged as prudent in the past.

Source: MPUC Docket No. 95-462, December 31, 1996; H.P. 1274 - L.D. 1804, "An Act to Restructure the State's Electric Utility Industry," signed May 1997.

MARYLAND

The Commission will allow recovery of verifiable, prudent and fully mitigated stranded costs. Utilities are to make filings by March 1998 concerning their stranded cost and mitigation estimates, the period of proposed recovery and collection mechanism. If a utility seeks securitization treatment of stranded costs, it should demonstrate the existence of benefits to residential and small commercial customers by such an approach.

The Commission will make its determinations concerning stranded cost categories, quantification methods and possible sharing of stranded costs at a later time.

A rate cap will be imposed from April 1999 to April 2001. The rate cap will be inclusive of any stranded cost charge that is allowed during that time frame.

Source: MPSC Case No. 8738, December 3, 1997.

MASSACHUSETTS

Utilities should have a reasonable opportunity to recover nonmitigatable stranded costs if no rate increase results. Recoverable costs include generating assets, long-term purchased power agreements, nuclear entitlements and regulatory assets. Certain employee-related costs (severance payments, retraining) can be included in stranded cost requests as well. Collection of all stranded costs is to be through a non-bypassable mechanism.

While there is no explicit regulatory compact (no promise to protect shareholders against the risk of regulatory change), stranded cost recovery is justified because of need to honor existing regulatory commitments and maintain the faith of the financial community.

No fixed time period is set for recovery of stranded costs, but should generally be assumed to be over the life of the generating asset, power contract or regulatory asset. All utilities receiving stranded cost recovery are to receive a comprehensive audit of claimed stranded cost categories first.

Only utilities that sell their non-nuclear generating assets or transfer them to an affiliated company may receive 100% stranded cost recovery. Transfer of assets to an affiliated company will be valued at highest price per kW resulting from a New England asset sale transaction. If a utility does not divest generation, the Commission is to use a market valuation for determining its stranded costs. Companies using administrative methods should reflect assumptions as to the likely expectations of a successful bidder as to the operating costs and marketing potential associated with a divested facility. Mitigation measures should include asset sales, energy sales, renegotiation of purchased power obligations and voluntary write-offs. Mitigation of stranded costs is essential to allowing customers their fair share of benefits from electric restructuring. The return allowed on stranded cost assets will be inversely related with the magnitude of these costs.

Securitization will only be authorized for those utilities divesting their non-nuclear generation.

A 10% rate reduction is mandated for 1998, with another 5% reduction to occur in the following year.

The stranded cost balance should be reconciled every 18 months after March 2000. If it is determined that the utility has overrecovered stranded costs, then credits are to be issued to customers.

Source: D.P.U. 96-100, Model Rules and Legislative Proposal, December 30, 1996; "Act Relative to Restructuring the Electric Utility Industry in the Commonwealth," passed November 1997.

MICHIGAN

Stranded cost recovery is approved for prudent past costs. The existence of mutual obligations between a utility and its customers, similar to a "regulatory compact" is noted. Regulatory assets, capital costs of nuclear facilities, capacity components of power purchase agreements, employee retraining costs and costs to set up a direct access system are the categories of potential stranded costs to be considered.

The uncertainty of the future market price of electricity and the level of mitigation by utilities makes true-ups of stranded costs essential.

The initial groups of customers receiving retail access (2-1/2% of total customers) will be chosen through a bidding process by which the customer indicates the amount they are willing to pay as a transition (stranded cost) charge. The highest bidding customers will be chosen. By 2002, all customers are to pay the same cost based transition charge.

While securitization may be a desirable means to ensure that all customers receive rate decreases under a new regulatory regime, no decision on the use of securitization of stranded costs will be made until the legislature has a chance to address the issue and certain related tax questions are resolved.

No other specific stranded cost matters were addressed by the Michigan Commission in its initial restructuring order. In a subsequent order, the Commission ruled that actual percentages of customers leaving the incumbent utilities' systems, the actual transition costs collected by the utility through the previously discussed bidding process, and the actual market prices paid by retail access customers should be used to true-up stranded cost collections, as opposed to use of what it viewed as "market price proxies." Also, Consumers Energy's proposed "capacity auction" method of quantifying stranded costs was rejected.

Sources: MPSC Case No. U-11290, June 5, 1997; MPSC Case No. U-11454, October 29, 1997.

MONTANA

Stranded cost recovery should be allowed for QF contracts, regulatory assets and (for four years only) generating assets and long-term contracts. Reasonable mitigation efforts are required. Recovery is to be through a non-bypassable charge to all customers.

A two-year rate moratorium will be applied beginning in July 1998 (certain exceptions are granted to this requirement).

Transition (securitization) bonds may be issued, if the savings benefit customers and their term does not exceed 20 years.

Source: Senate Bill 390, "The Montana Electric Utility Industry Restructuring and Consumer Choice Act," effective May 1997.

NEW HAMPSHIRE

Stranded cost recovery is allowed for "net sunk generation costs not recoverable under retail access." Stranded costs include regulatory assets and nuclear decommissioning, but do not include variable generation costs, employee costs and generation-related deferred tax liabilities. The Commission submitted with its Order a voluminous "Legal

Analysis" which stated its belief that utilities are not entitled as a matter of law to full recovery of stranded costs associated with the introduction of competition. Recovery will be accomplished through a user surcharge via the local distribution company.

The sale or spin-off of assets is described as the most accurate way to calculate stranded costs. Neither of these two alternatives is required, but utilities will not be allowed to sell at retail in the service territories of their affiliated distribution companies if they do not divest their generating assets.

Among the methods of mitigating stranded cost amounts addressed in the Order are sale or spin-off of assets, voluntary write-downs, securitization, and others. The PUC recommends the legislature proceed cautiously with securitization initiatives, as true-ups of stranded costs would be foreclosed by use of this option.

Determination of the amount of stranded cost recovery will be made on a case-by-case basis. Utility management decisions will be reviewed in making this determination. Also, the amount of recovery will be dependent upon the relationship between the utility's rate levels and the average regional rate (the higher the utility's rate above the regional average, the less cost recovery). Full stranded cost recovery may be anti-competitive, in that generating companies could be free to drop their price in a competitive market and suffer no loss if allowed stranded costs.

Note: The Commission's Order on restructuring is not being fully implemented due to a utility's appeal of its stranded cost provisions.

Source: NHPUC Case No. DR-96-50, "Final Plan," February 28, 1997.

NEW JERSEY

Stranded costs directly related to utility power supply will be allowed. This includes generation plants, and long and short-term power contracts with utilities and nonutility generators. Generation-related regulatory assets and nuclear decommissioning will not be considered stranded; they will continue to be collected through distribution rates. The existence of a regulatory compact is implicitly affirmed, but does not mean 100% recovery of stranded costs is mandated. The collection will be in the form of a "market transition charge," a non-bypassable component of the customer's bill.

The existence and amount of recoverable stranded costs will be determined on a case-by-case basis for utilities. Recovery of stranded costs is to be allowed concurrently with retail access, and should only extend for four to eight years. Utilities are to propose a market valuation method in their stranded cost filings. All reasonable mitigation methods should be employed, such as sale of excess generation capacity, accelerated depreciation, reduced return on uneconomic assets, and buy-out or renegotiation of long-term contracts. Securitization holds promise as being part of the solution to the stranded cost problem, and will be studied further. However, use of securitization will not be the sole source of potential rate reductions. The possible need for asset divestiture to perform an appropriate market valuation will be considered later.

100% recovery of stranded costs is not contemplated, with a cap on overall rate levels the preferred method of allocating costs to shareholders. Also, a 5-10% rate reduction will be mandated concurrent with the start of retail access.

Note: Commission findings on stranded cost issues are not enforceable until legislative approval is received.

Source: "Restructuring the Electric Power Industry in New Jersey," April 30, 1997.

NEW YORK

Stranded cost recovery of prudent, verifiable and nonmitigatable costs is approved in concept, with amounts and timing of recovery to be determined on a case-by-case basis. In making this finding, explicit regulatory compact or mandated prudent investment recovery arguments were rejected. Utilities should have a reasonable opportunity to recover stranded costs, though this opportunity must be balanced with the goals of lowering rates, providing for customer choice, maintaining reliability, and fostering economic development. Recovery is to be through a non-bypassable distribution charge.

Utilities are encouraged to devise "creative" ways to mitigate stranded costs, including renegotiation of IPP contracts. Generation divestiture is encouraged as a way to mitigate market power concerns, but is not required. (In subsequent case-by-case settlements, utilities have agreed to divest a certain percentage of their generating assets.)

Rate caps are an appropriate tool to prevent cost shifting associated with stranded cost recovery.

Source: NYPSC Opinion No. 96-12, May 20, 1996.

OKLAHOMA

Legislation directed that procedures be developed to identify, quantify and recover prudent, verifiable and unmitigated stranded costs. No increase in rates will be permitted as a result of stranded cost recovery. Recovery will be over a period from three to seven years.

The Commission will consider use of a distribution access fee to recover stranded costs. No further policy decisions were made on stranded costs in the legislation.

Source: "Electric Restructuring Act of 1997," signed April 1997.

PENNSYLVANIA

Recovery of known and measurable net generation-related stranded costs is allowed, after mitigation. Existence of a regulatory compact concept is implicitly agreed to. However, a utility must demonstrate that it has undertaken substantial mitigation, and the Commission must find that the amount allowed for recovery is "just and reasonable." Recovery of stranded costs is to be through a non-bypassable charge on customers accessing the transmission or distribution networks. Recovery of stranded costs shall not result in shifts of class revenue requirement. Stranded cost recovery is to be granted related to new self-generation initiatives.

The types of costs to be potentially considered as stranded include: generating assets, long-term purchase power commitments, renegotiation of NUG contracts, regulatory assets and decommissioning costs, disposal of spent nuclear fuel, and employee retraining and early retirement costs.

Recovery of stranded costs can begin prior to retail competition (as early as the effective date of the legislation). Though some flexibility is granted to the Commission in regard to the endpoint of recovery, in general the legislation cuts off recovery nine years after the legislation becomes law.

No specific methodology for calculating stranded costs is prescribed in the law. Nor are any specific mitigation techniques required, though the approaches of accelerated depreciation and amortization, minimization of new capital spending, reallocation of depreciation reserves, sale of idle or underutilized existing generation assets, maximization of market revenues, and issuance of securitized debt are options listed in the legislation. Divestiture of generating units is allowed, but not required. The law calls for annual reconciliations of actual stranded costs and the amount collected in rates.

Securitization is allowed for stranded costs, up to limits to be set by the Commission. Utilities can seek expedited treatment from the Commission for securitization requests. There is to be a rate cap on customer bills for up to 54 months after the legislation passes (or until stranded costs have been collected in entirety). Certain exceptions are granted to the rate cap requirement, concerning the need for possible extraordinary rate relief and other factors.

Source: House Bill 1509, signed December 1996.

RHODE ISLAND

The statute states that utilities should have a reasonable opportunity to recover costs prudently incurred in relation to the past legal obligation to provide service at reasonable costs. Types of stranded costs include regulatory assets, nuclear decommissioning, purchased power contracts and generating plants. These amounts will be collected through a non-bypassable transition charge.

Stranded costs may be recovered through the year 2009. From July 1997 to December 2000, the transition charge will be valued at $.028/kWh. After 2000, the amount authorized will be sufficient to recover the remaining authorized costs reflecting a true-up of the amounts already collected. The equity return on unrecovered generation plant and regulatory asset stranded costs will be set at one percentage point above the prevailing debt rate for BBB long-term bonds.

All power suppliers receiving stranded costs must put on the market at least 15% of their non-nuclear generating facilities. Utilities can retain 10% of the savings from renegotiation or buy-out of long-term power contracts. To mitigate stranded costs, and prevent residential customers from paying higher rates as a result of competition, all distribution companies will have a performance-based rate plan in place by the end of 1998.

Source: "Rhode Island Utility Restructuring Act of 1996," enacted August 1996.

Appendix D

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SCHEDULES 2 THROUGH 3

ARE

DEEMED

HIGHLY CONFIDENTIAL

AQUILA, INC.
CASE NO. ER-2004-0034
MISSOURI PUBLIC SERVICE COMMISSION
DATA REQUEST NO. MPSC-377

DATE OF REQUEST: October 8, 2003

DATE RECEIVED: October 8, 2003

DATE DUE: October 28, 2003

REQUESTOR: Cary Featherstone

BRIEF DESCRIPTION: Stranded Investment Studies

QUESTION:

Please provide any stranded investments studies, analyses, that Aquila (UtiliCorp United) and any of its affiliates including but not limited to Missouri Public Service, St. Joseph Light & Power and any other regulated divisions completed last 5 years.

RESPONSE: We are not aware of any studies, analyses completed in last 5 years

ATTACHMENT: none

ANSWERED BY: John W. McKinney

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SIGNATURE OF RESPONDENT

UTILICORP UNITED
CASE NO. ER-01-672
DATA REQUEST NO. MPSC-365A (Supplement)

DATE OF REQUEST: October 2, 2001

DATE RECEIVED: October 2, 2001

DATE DUE: October 22, 2001

REQUESTOR: Cary Featherstone

QUESTION:

2. Does a) UtiliCorp United; b) Missouri Public Service; c) any other UtiliCorp affiliate have policy(ies) that all divisional generating capacity needs will be met by purchase agreements (affiliated or non-affiliated) as opposed to the divisions constructing and owning generating units?

3. a) If so, please identify and describe such policy(ies) and provide the advantages and benefits to each: i. UtiliCorp United; ii. Missouri Public Service; iii. Any other UtiliCorp affiliates for such policy(ies). SEE ATTACHED

   b) Provide any supportive information such as policy(ies), position papers, memorandum and letters describing and supporting such position, and any other documentation that exists regarding UtiliCorp divisions not constructing and owning generating units

RESPONSE:

1. The Company has no formal policies or guidelines requiring resource additions to be purchased.

   Resource additions are planned in compliance with the Missouri integrated resource planning (IRP) rules.

   In addition to complying with the IRP rules, individual additions are reviewed based upon prevailing and/or expected business conditions

   The Company believes that the current regulatory climate does not warrant the business risks associated with constructing and owning rate-based generating plants.

ATTACHMENTS: None

ANSWERED BY: Steve Ferry

SUPPLEMENTAL REQUEST (Dated October 30, 2001):

UtiliCorp's response to the original Data Request No. 365 states, in part, that "the Company believes that the current regulatory climate does not warrant the business risks associated with constructing and owning rate-based generating plants." Please provide the following regarding this statement:

11/3/01 [illegible]

1a. What does UtiliCorp mean by the statement "the Company believes that the current regulatory climate does not warrant the business risks associated with constructing and owning rate-based generating plants "; b) Provide all examples where the "current regulatory climate does not warrant the business risks associated with constructing and owning rate-based generating plants."

2. Please give all reasons why "the Company believes that the current regulatory climate does not warrant the business risks associated with constructing and owning rate-based generating plants."

3. When has the company been harmed from "the current regulatory climate". in constructing and owning rate-based generating plants"? Provide all specific examples when such has occurred.

4. Provide all support for items 1 through 3 above included but not limited to Commission Reports and Orders, position statements, letters of correspondence, any other documentation supporting 1 through 3 above, etc.

SUPPLEMENTAL RESPONSE:

The statement, "The Company believes that the current regulatory climate does not warrant the business risks associated with constructing and owning rate-based generating plants." speaks for itself and no further response is necessary or would be a proper subject for a Data Request.

SUPPLEMENTAL ATTACHMENTS: None

SUPPLEMENT ANSWERED BY; Steve Ferry

UPDATED VALUATION OF ARIES UNIT CAPACITY: MPS SHARE OF CASS COUNTY LEASE COSTS

MPS Capacity Charges, per Contract		
Off-Peak Pricing ((200 MW x 1000) x \$5.90 x 6)		\$7,080,000
Peak Pricing ((200 MW x 1000) x \$5.90 x 6)		\$7,080,000
((300 MW x 1000) x \$7.50 x 6)		\$13,500,000
Total MPS Capacity Charges		**\$27,660,000**
Valuation of Total Aries Capacity, Using MPS Contract Terms		
Off-Peak Pricing ((585 MW x 1000) x \$5.90 x 6)		\$20,709,000
Peak Pricing ((200 MW x 1000) x \$5.90 x 6)		\$ 7,080,000
((385 MW x 1000) x \$7.50 x 6)		\$17,325,000
Total Capacity Charges		**\$45,114,000**
\$27,660,000/\$45,114,000 =	61.31%	(MPS Responsibility for Aries capacity costs)
Total 2003 Capacity Costs (per Cass County Lease)	\$	28,400,000
	X	.6131
MPS Share of Aries Capacity Costs (Line A)		**\$17,412,040**
Fixed O&M Costs (12 Mos. Through Sept. 2003)		\$7,500,000
	X	.6131
MPS Share of Aries Fixed O&M Costs (Line B)		**\$4,598,250**
Total MPS Share of Aries Costs (Line A + B)		**\$22,010,290**

Schedule 6