STRANDED COST FOR
RETAIL ELECTRIC COMPETITION

A REPORT TO THE
MISSOURI PUBLIC SERVICE COMMISSION'S
TASK FORCE ON RETAIL ELECTRIC COMPETITION

FROM
THE TASK FORCE'S WORKING GROUP ON
STRANDED COST

MARCH 1998

Table of Contents

CHAPTER I

Introduction

This report constitutes the work product of the Stranded Cost Working Group which is a part of the Missouri Public Service Commission's Task Force on Retail Electric Competition in Missouri, Missouri PSC Case No. EW-97-245.

The Working Group met on twelve separate occasions, with the first meeting on August 22, 1997, and the final meeting on March 4, 1998. The initial meetings of the Working Group were designed for information gathering and to allow the Working Group members to become informed about the issues related to stranded costs. The Working Group was fortunate to have the benefit of presentations by two outside experts. Eric Hirst of Oak Ridge National Laboratories addressed the Group in October 1997, regarding the subject of stranded cost in general, and highlighted the ORNL publication on stranded cost of which he is a co-author. On February 25, 1998, the Group heard a presentation from Susan Weil of Lamont Financial Services Corporation on the issue of securitization.

The primary goal of this report is to identify the key issues involved with the identification, quantification, mitigation and collection of stranded costs, and to present alternatives and policy options. The pros and cons and impacts of various options and courses of action are delineated in the various chapters of the report, as appropriate. Conclusions and recommendations are expressed where the Group as a whole was able to reach consensus. Because of the diversity of interests represented by Working Group members, only general conclusions and recommendations are possible. Individual Working Group members may not agree with each statement, conclusion or recommendation in this report.

The following are the members of the Stranded Cost Working Group:

Chairman:	Maurice Brubaker, Brubaker & Associates, Inc.
Vice-Chairman:	Duane Galloway, City Utilities of Springfield
Staff Vice-Chairman:	Mark Oligschlaeger, MPSC Staff

Members:	Don Brandt, AmerenUE
	Hon. Gary Burton, Missouri House of Representatives
	Todd Decker, Citizens Electric Corporation
	Hon. Charles Dumsky, City of Sugar Creek

Ivan Eames, Central Missouri County's Human Development Corporation
John Gallagher, Kansas City BOMA
Chris Giles, Kansas City Power & Light Company
Scott Jaskowiak, Laclede Gas Company
Ryan Kind, Office of the Public Counsel
Steve Mahfood, Missouri Environmental Improvement and Energy Resources Authority/Department of Natural Resources
Ken Midkiff, Sierra Club
Steve Svec, Chillicothe Municipal Utility

CHAPTER II

Definitions of Stranded Costs

A. Concepts

1. Background

The concern over stranded costs in the electric industry has arisen due to widespread recent efforts to introduce competition into that industry. Based on an assumption that electric utilities are natural monopolies, the prices charged for electric service have generally been constrained by regulation over most of the past century. Under current forms of regulation, the utilities have charged rates based on regulatory findings as to the amount of their prudently incurred expenses and investment. Thus, electric rates have been based on the reasonable and prudent embedded costs of the utilities incurred to provide service to customers.

If competition in generation is feasible and is allowed in the electric industry in Missouri through the policy decisions of legislators and regulators, some portion of electric prices will no longer be dictated by the decisions of the public utility commission, but instead will be determined (at least in theory) by the supply and demand forces of the marketplace. Economic theory holds that the prices of competitive goods and services should approximate the long-run marginal cost of producing the good or service in question. The marginal cost of producing electricity may not be the same as, and in fact may differ significantly from, the current embedded cost of electric production reflected in current rate levels. Utilities whose embedded cost of electricity is in excess of the market price of electricity as determined in an open and free market will suffer the phenomenon of "stranded costs." Stranded costs can therefore be simply defined as the embedded investment made by electric utilities to provide service to customers that will not be recoverable in the price of electricity set in a competitive market. (It is expected that some utilities' embedded cost levels will result in prices that are less than the expected marginal cost of producing electricity. Therefore, these utilities would be able to raise the prices currently charged for electricity in a competitive market. This phenomenon is referred to in this Report as "negative" stranded costs.) This entire discussion is addressed in more detail in Report III, "Changes in the Pricing of Electricity: An Explanation of Regulated and Market Pricing," by the Staff Team of the Missouri Public Service Commission on Electric Industry Structure and Market Power, dated December 1997.

The perceived gap between the estimated market price of electricity and the current embedded cost of electricity currently reflected in rates, which has fueled the push to introduce competitive forces into the industry, has been caused by several factors. One reason is recent technological advances in the production of electricity from gas-fired generators, which has significantly reduced the marginal cost of electricity compared to prior generation technologies. Another reason is that certain generating technologies (such as nuclear power) and governmental rules (such as mandated utility purchases of power from independent power producers at "avoided cost") for various reasons produced power prices far above projected levels, and ultimately far above current estimates of the market price of electric power.

Stranded costs can be incurred by any type of utility that has been subject to regulation and will be subject to competitive pressures. Those utilities may include investor-owned utilities, municipal utilities, and cooperatives, depending on the extent of deregulation (if any) that is decided upon for Missouri through the restructuring process. Since the Commission does not regulate the municipal and cooperative utilities (with the exception of Citizens Electric Corporation), the focus of this report is on the investor-owned utilities. (The views of the State's municipal utilities and cooperatives on stranded cost matters at this time are attached to this report as Appendices A and B, respectively.)

Stranded costs are not an isolated concern of the electric industry. Any time a previously regulated industry is introduced to competitive pricing concepts, stranding of costs may occur. In fact, prior to the recent discussion of the possible implementation of competition for the electric industry, some deregulatory actions took place in the regulated natural gas and telecommunications industries. Accordingly, stranded costs arose as a concern to both those industries as the prices charged became more subject to market forces. The literature available on the subject suggests that incumbent utilities in both the natural gas and telecommunications industries received partial, not total, recovery of any stranded costs they incurred as a result of the move to competition.

2. Terminology

There are any number of terms currently in use around the country that signify the concept of "stranded costs" described above. These terms include stranded investment, above market costs, uneconomic costs, costs in excess of market prices, and others. Because "stranded cost" is the most widely used term of art for the subject matter of this report, we have chosen to use this term consistently throughout the report.

3. Stranded Costs in Missouri

Because stranded cost estimates depend, among other things, on an assumed future market price of power, it is impossible at this time to provide a definitive picture of future stranded cost levels applicable to Missouri. There currently exists a wide range of estimated values for the future competitive price of electricity. Under one set of assumptions, there may be no stranded costs at all in Missouri at the onset of competition; under another set of assumptions, there may be a significant level of stranded costs. Given the uncertainty that now surrounds the timing of the introduction of any competitive initiatives in this state, as well as the uncertainty regarding the future market price of electricity, among other factors, the Working Group did not believe it would be a productive use of its time and resources to attempt at this time to estimate stranded costs for Missouri jurisdictional utilities. (See Chapter III, Section E, for estimates that have been made by independent parties.) Nonetheless, there are several conclusions that can reasonably be reached at this time.

First, any positive stranded cost levels that may be exposed in Missouri if competition is introduced are likely to be largely associated with the two nuclear units that currently provide service to Missouri customers. These units are the Callaway unit, owned in entirety by the Union Electric Company, and the Wolf Creek unit in Kansas, owned 47% by Kansas City Power & Light Company. Second, even if some Missouri utilities are believed to be likely to incur positive stranded costs if competition is introduced, (i.e., their rates will be above market levels), it is equally likely that other Missouri utilities will experience negative stranded costs if competition comes (i.e., their current rates will be below market levels.) Any restructuring policy in this state regarding stranded costs must be responsive to the situation in which both positive and negative stranded costs will be experienced by different utilities, and attempt to provide appropriate customer and shareholder protection measures under either scenario.

4. Other Jurisdictions

Other state jurisdictions (and the Federal Energy Regulatory Commission) have a considerable head start on Missouri in considering different components of stranded cost policy. We have attached as Appendix C a summary of the actions and decisions made by other state jurisdictions of which we are aware concerning stranded cost recovery policies, through the end of 1997.

The experiences of other jurisdictions in regard to stranded costs should only be applied with caution to Missouri. Most of the states reflected in Appendix C appear to be higher cost electricity states than Missouri; indeed, that is why there were greater pressures on these jurisdictions to move expeditiously on electric restructuring matters than in Missouri. Accordingly, the magnitude of stranded costs in these states will likely be greater than that which may be experienced in Missouri, and the approaches used in these states may or may not be appropriate for Missouri.

However, it is possible to generalize to some extent about the actions these states have taken regarding stranded costs. First, most jurisdictions appear to have provided for the opportunity for recovery of most or all of the stranded costs their utilities will incur once competition is implemented. Second, most jurisdictions addressing stranded costs of which we are aware state as a matter of policy that utilities must mitigate their stranded costs prior to recovery. Third, most jurisdictions that express an opinion on quantification methodologies state a general preference for market-based methods of calculating stranded costs, compared to administrative methods. These topics will be addressed separately in this report.

B. Specific Items

1. Introduction

Before discussing individual categories of costs that are commonly thought to be susceptible to potential stranding, it should be emphasized that any type of generation cost can be stranded if the generating component of electric service is opened up to competitive pressures. This includes direct costs of generation, indirect costs, overhead costs, allocated costs, etc. If competition is allowed in this jurisdiction, any cost that would properly be reflected in an unbundled rate for generation will be potentially exposed to stranding.

Also, any examination of stranded cost recovery claims should encompass all categories of costs that are agreed to be appropriate potential sources of stranded costs. For example, basing a claim for recovery of stranded costs solely on regulatory assets, with no analysis of long-term contracts and generating unit assets (if all these costs are deemed to be appropriate stranded cost categories), might result in a misleading picture of the utility's actual stranded cost exposure. In particular, all potential sources of both positive and negative stranded costs should be considered in determining the amount of stranded cost recovery that is reasonable (if any recovery of stranded costs is ultimately allowed).

The following categories of generation costs are widely thought to be the most material contributors to stranding of costs. Of the categories listed, generating assets and long-term contracts have been treated as stranded costs in every jurisdiction that has made a policy determination on stranded cost categories. With few exceptions, most jurisdictions have also included regulatory assets as an allowable stranded cost. For the categories of nuclear decommissioning and public policy costs, there appears to be no consensus on stranded cost treatment in other jurisdictions; some judging these items as acceptable stranded costs, with other states refusing such treatment.

Some jurisdictions have proposed to include in stranded cost charges amounts related to employee costs (severance packages, retraining expenses, etc.) and other restructuring costs (costs to set up independent system operator structures or power exchanges, etc.). We have chosen not to list these categories in this section, because some believe they do not represent true stranded costs but are rather in the nature of "transition costs." Also, some believe that the revenue enhancement mitigation techniques that are described in Chapter V of this report should be considered as an additional stranded cost category that can provide negative offsets to positive stranded costs when the net magnitude of stranded costs is calculated. If potential revenue enhancements (sometimes referred to as "transition benefits") associated with the competitive opportunities expected in a restructured electric industry are included in stranded cost calculations, then these same revenue enhancements should not be considered to be mitigation techniques.

2. Cost Categories

a. Generating Plants This category includes the generating units used by utilities to produce power for sale to their customers or for sale to other utilities. These units run the gamut between the high capital cost baseload nuclear and coal units that produce the bulk of the power actually serving customers and the relatively low capital cost combustion turbines generally used to meet load peaks only. In an industry that is viewed as capital intensive, capital needs associated with generating units ordinarily have been the greatest contributor to electric utilities' capital investment, and therefore are potentially one of the largest sources of stranded costs for those utilities that face above market costs.

Of the various types of generating units, it is widely held that nuclear plants are likely to be responsible for most (but not necessarily all) of the potential stranded investment associated with generating assets. While nuclear units can be among the lowest cost units on a short-run marginal cost basis, the very high capital costs associated with this type of technology have led to a widespread actual result that most nuclear units will produce above market-priced power.

Other types of generating technologies, including fossil fuel units (coal and gas-fired), are viewed as much less likely than nuclear facilities to result in stranded costs in a competitive market. In fact, some studies have indicated that, taken as a whole, generating technologies other than nuclear will produce net negative stranded costs nationwide. This means that in the aggregate, the book value of these types of generating facilities will be less than the estimated market value of these units. In general, we see no reason to quarrel with this expectation as it applies to Missouri specifically.

Given that a utility's generating units can produce either positive or negative stranded costs, it is crucial that all of a utility's generating facilities be analyzed for stranded cost exposure if stranded costs are to be quantified, so that a company's overall stranding situation can be properly analyzed. Examining some, but not all, of a utility's generating units for potential stranded costs can present a slanted and biased depiction of its true stranded cost exposure.

b. Long-Term Contracts Utilities do not generally supply all the power necessary to serve customers within their service territory from generators they themselves own or have an interest in. Nor does all the power their generating units provide necessarily go to customers within their service territories. Instead, an "interchange" market exists in which utilities can make power transactions with each other. This market allows utilities to purchase power from other power producing entities when such purchases are less expensive than the utilities producing the power themselves. The interchange market also allows utilities to sell power to other entities when the utility has capacity on its system beyond what is needed to serve its own customers at any point in time.

Sometimes utilities enter into "firm" long-term contracts to either buy or sell power to other entities, often in lieu of the buying utility constructing capacity to serve its customer base. (The term "firm" means that the selling utility essentially guarantees that the power contracted for will be provided when the buying entity needs it.) Under firm contracts, the buying utility usually pays a "capacity charge" to the selling entity for the capacity reserved for its use, and an "energy charge" to reimburse the selling utility for the incremental costs of the power produced for sale in the interchange market. The capacity charge is a fixed cost of the transaction, payable whether power is taken by the purchasing utility or not; with the energy charge being variable with the power actually purchased. Therefore, it is the fixed capacity charge associated with long-term power contracts that is susceptible to stranding under the onset of competition. Such a charge (which may have been set years ago) may be excessive compared to the cost of power that can be obtained in a competitive marketplace.

Utility long-term contracts for fuel supply can also contribute to potential stranding problems, if such contracts reflect liabilities for future supply and transportation costs that are above competitive levels.

Unlike generating stations, which are assets giving rise to potential stranded costs, capacity charges for long-term contracts are liabilities to the purchasing utilities. However, in most respects, stranded costs associated with long-term contracts are similar to stranded costs associated with generating assets. Most important, stranded costs related to long-term contracts can be either positive or negative. In other words, the capacity costs associated with long-term contracts can in some instances be cheaper than the capacity cost of power available in a competitive electric market. Therefore, it is again important that the stranded costs associated with all of a utility's power contracts be analyzed, or a misleading and inaccurate picture of that company's stranded cost exposure may be obtained.

Some utilities around the country have very significant potential stranded costs associated with long-term power contracts. Most of these are connected to the PURPA Act of 1978, which required utilities to purchase power from certain "non-utility generators" (NUG) at the "avoided cost" of power to the purchasing utility. ("Avoided cost" is the cost to the utility of obtaining the next increment of capacity needed to serve customers.) The utilities' avoided costs were determined administratively by regulators, which in many instances produced estimates that in retrospect grossly overstated the actual avoided cost values. Where NUG purchases are common, such as in California and the Northeast, long-term contract stranded costs may exceed stranded costs related to generating units for a given utility. However, while there may be individual contracts that may give rise to positive stranded costs in Missouri, there have been no significant NUG purchases under PURPA in this jurisdiction. For this reason, we do not foresee that this category of stranded costs will be a serious problem in Missouri.

c. Regulatory Assets These items are assets created by the actions of regulators. For example, a regulatory commission might order that a particular cost ordinarily charged to expense by the utility in the period it is experienced instead be capitalized on the utility's books as an asset and recovered in rates from customers over a defined period of time. These types of costs might include natural disasters (storms and floods), deferred taxes or costs the utility is specifically ordered by regulators to incur. The opposite of a regulatory asset is a regulatory liability, which is a gain a utility would normally book to income in the year it is experienced, but regulators instead order be reflected as a liability on the utility's books where it can be passed on to customers in rates over a set period of time.

Regulatory assets and liabilities can be stranded because they have value to utilities or their customers only because the utility's rates are set by regulators, who have the power to reflect the impact of regulatory assets and liabilities in rates. In contrast, in a competitive market, market forces will establish the ongoing prices for electricity generation, and the previous decisions of regulators to account for certain generating costs in a particular manner will be irrelevant. (Note: only those regulatory assets and liabilities that are directly or indirectly related to the generation function can be stranded due to electric restructuring. Transmission and distribution regulatory assets and liabilities will not be subject to stranding.) Therefore, under a competitive pricing regime, generation regulatory assets will be valueless, and the entire balance of a utility's generation regulatory assets (net of regulatory liabilities) should be considered stranded under competition.

In contrast to regulatory assets, stranded regulatory liabilities are a source of negative stranded costs to utilities under competition, and should be considered in any stranded cost analysis along with regulatory assets. Some jurisdictions consider over funded utility pension plans (for which ratepayers are the source of cash contributions) as a regulatory liability for stranded cost purposes. Other jurisdictions consider the amount of deferred taxes paid in rates by customers in advance of payment to the taxing authority by the utility also to be a valid offset to stranded costs, even though such tax prepayments are not technically classified as regulatory liabilities by utilities.

d. <u>Nuclear Decommissioning</u> This item refers to expected future expenditures to dismantle nuclear generating units and take necessary efforts to clean up the generating sites. The costs to decommission nuclear facilities are expected to be quite substantial, and under current law utilities are required to precollect in customer rates costs associated with nuclear decommissioning and deposit them in a trust fund. (Precollection in a trust is not only predicated on the expected substantial liability for this item, but also on the public health concern that the financial ability of the utility to undertake nuclear unit clean-up not be impaired when the unit stops generating electricity.) In a competitive market, it is expected that nuclear decommissioning costs will be stranded, as entities competing with incumbent utilities will not have to reflect those specific costs in the prices charged.

One important policy question regarding stranded cost recovery related to nuclear decommissioning is whether such calculations should be cut off to reflect only the current estimate of future decommissioning costs now reflected in customer rate levels or whether stranded cost recovery should be updated to reflect changing estimates for this cost item. Also, if stranded cost recovery is allowed only for a relatively short period of time, should nuclear decommissioning stranded costs similarly be subject to a shortened time frame for recovery? Because the public health aspects of nuclear decommissioning costs differentiate this item from other potential sources of stranded costs, some jurisdictions have made policy decisions to collect nuclear decommissioning costs in a separate charge from other stranded cost quantifications, so no specific time limit for recovery will apply to this discrete item.

e. Cost for Public Benefits Programs This item relates to obligations of utilities imposed by governmental or regulatory bodies, the costs of which are determined to be the public policy of the state. These costs might include tax collection, environmental improvement and compliance expenditures, funding to help low income customers, research and development expenses for energy efficiency and renewable resource technologies, demand-side planning costs, and any other type of expenditure for a public purpose that is being funded through utility rates, as opposed to general taxation revenues.

These costs will be stranded if there is no obligation imposed on potential competitors of incumbent utilities to similarly incur these expenses or the incumbent is not allowed to continue to collect these costs through a nonbypassable wires charge. It is our understanding that the Public Interest Work Group will address the appropriate disposition of this category of costs in its report to the Retail Electric Competition Task Force.

CHAPTER III

Identification and Determination of Stranded Costs

A. Introduction

The question of the best method to calculate stranded costs is controversial, largely because the values of the major assumptions that enter into the calculation (in particular, the future market price of electricity) are uncertain at any point in time. Therefore, stranded cost calculations are dependent in large part on forecasts relating to unpredictable future events, and the amount of stranded cost recovery advocated by any party is inherently tied to that party's subjective judgment.

The major dispute in stranded cost quantification that has arisen in other jurisdictions is whether an "administrative" or "market" type of approach to calculation is most appropriate. This question will be examined in some detail in this report. There is also a question as to the level of detail necessary in making stranded cost determinations ("top down" versus "bottom up" approaches), which primarily relates to administrative methods of calculating stranded costs. This concern will be examined briefly as well.

Most of the controversy surrounding stranded cost quantification specifically involves the cost categories of generating asset and long-term purchase power contracts. This is because any stranded costs associated with these categories result from an excess of their book values over their market values. The market values of these categories can only be derived by actually placing them on the market or by performing a simulation to estimate how much the assets and/or contracts will be used under conditions of true competition. Either approach to valuing the generating assets and contracts has significant limitations under certain circumstances, as will be discussed.

Quantification of the other stranded cost categories listed in Chapter II should not be as difficult. Regulatory assets by definition should have a market value of zero under competition; so the entire net balance of a utility's regulatory assets on the books at the time competition is initiated should be considered as part of stranded costs. There are already processes set out in this jurisdiction to estimate future nuclear decommissioning costs; these methods could also be used for stranded cost quantification purposes. Quantification of public policy costs for stranded cost purposes should also be relatively straightforward.

Finally, the issue of the use of "true-ups" to correct stranded cost estimates over time is related to the quantification method used to calculate stranded costs, and will be discussed in this section of the report as well.

B. Overview of Market and Administrative Methods of Calculating Stranded Costs

1. Market-Based Methods

Stranded costs can be quantified using market valuations of generation assets or competitive power prices. Market mechanisms provide an objective and definitive measure of the market value of assets. Thus, the use of such mechanisms can avert the need for prolonged legal proceedings to establish subjective, administratively determined market price levels to quantify stranded costs. Market mechanisms are attractive because the result of the market process *defines* the market value of the assets. Entities willing to buy assets that may be the source of potential stranded costs will by necessity base their proposed purchase price on assumptions concerning the future market price of electricity and their ability to profitably operate the generating asset or group of assets in a competitive market. The proposed purchase price of the asset(s), if accepted, becomes a fixed, one-time only valuation of the market value of the asset(s), and thus will produce a fixed and unchanging stranded cost value. This, in turn, would reduce much of the controversy surrounding the quantification of stranded costs. Under a market quantification approach, the purchaser of generation assets shifts the risk associated with changing values in the future market for electricity away from the former owner and its customers by assuming the risk itself.

While market mechanisms can reduce the litigation surrounding the quantification of stranded costs, this desirable feature is not without some downside risk. Because market mechanisms cannot be effectively subjected to a stranded cost true-up, such methods of quantifying stranded costs could result in customers paying excessive prices for power or utilities undercollecting stranded costs in a competitive environment. For example, if a market mechanism produces a competitive power price of 2¢ per kWh to quantify stranded costs, and the market clearing price subsequently rises to 4¢ per kWh within two years, customers would be required to pay a high stranded cost charge based on the initial market valuation of stranded costs, in addition to the higher power prices that ultimately prevail in the market. Some experts suggest that customers wishing to minimize their exposure to this eventuality can sign fixed price contracts or use price risk hedging mechanisms such as options contracts in competitive retail markets.[1]

[1]Jonathan Lesser and Malcolm Ainspan, Using Markets to Value Stranded Costs, *The Electricity Journal*, October 1996, p. 71.

Of course, market prices and competitive asset valuations will always fluctuate with changing market conditions. Therefore, a "snapshot" assessment of stranded costs based on a market mechanism will always contain a margin of error when that assessment is evaluated in hindsight. However, one can argue that because the market mechanism defines the market value of an asset at a given point in time, and the risk of an inaccurate forecast of future market values is assumed by the purchaser, ex post assessments of market asset values are inherently meaningless.

A major question in near term use of market methods to quantify stranded costs is whether the uncertainty inherent in the current transition to retail competition would cause bidders to significantly discount the prices they are willing to pay for generation assets, or whether the introduction of retail access is likely to have a sizeable impact on competitive power prices. For example, some analysts have suggested that the introduction of retail access could create upward pressure on competitive power prices relative to current levels by increasing the number of customers competing for a given supply of electricity.[2] However, it is unclear whether this phenomenon is likely to be realized if aggregate supply and demand levels for electricity remain relatively constant after the advent of retail competition. It has also been suggested that because there is little precedent for generation asset sales in the U.S., the risk associated with the absence of price comparables from prior asset sales could cause parties to discount the prices they are willing to pay for generation assets.[3]

On the other hand, it is possible that market mechanisms applied to today's market conditions could produce a price premium for generation assets. For example, generation asset sales that occur prior to the advent of retail competition to a particular market could garner high prices because they provide competitors with an easy means of entry into emerging power markets. For the reasons described above, it is possible that the application of market mechanisms to today's market environment could produce inaccurate quantifications of stranded cost levels in the long run.

Recognizing that market values may change over time for a variety of reasons, some of which are related to the advent of retail competition, one could consider delaying the market valuation in order to allow part of this phenomena to be reflected in the market. For example, if retail access is

---

[2]Judah Rose, Shanthi Muthiah, and Maria Fusco, Is Competition Lacking In Generation? (And Why It Should Not Matter), *Public Utilities Fortnightly*, January 1, 1997, p. 26.

[3]Jonathan Lesser and Malcolm Ainspan, Using Markets to Value Stranded Costs, *The Electricity Journal*, October 1996, p. 73.

to begin January 1, 2000, it might make more sense to perform the market valuation in 2001 than to do it in 1999. Doing it after retail competition is available would certainly allow for prospective purchasers to have the benefit of the experience of operating in a competitive retail market; while an early evaluation date would not.

While market mechanisms are in many respects more desirable than administrative determinations of stranded costs for reasons that will be discussed, the preceding discussion demonstrates that the use of market methods also entails a measure of risk. In essence, stranded cost quantification through market mechanisms is a "one-shot deal" that contains some downside risk for customers and utilities. The various risks and advantages of all stranded cost calculation methods should be considered before advocating any one conceptual approach.

2. Administrative-Based Methods

The quantification of stranded costs necessarily depends on the expected level of competitive market prices for electricity, as well as the future operating costs and capacity factors of existing generation assets. Small changes in the forecasted levels of these parameters can produce significant changes in the expected magnitude of a utility's stranded cost exposure.

Administrative methods of quantifying stranded costs rely on the results of a contested case proceeding before a regulatory commission to establish these parameters. With an administrative method using a "bottom up" (detailed) approach, computer models are often used to simulate a dispatch system for individual generating units operating under a competitive regime. A large number of assumptions must be made in order to perform the simulation. It is necessary to make a long-term forecast of the year-by-year values for market price of capacity, market price of energy, and operating costs associated with all existing generation assets. The generation asset costs that must be forecasted include fuel expense, operation and maintenance expense, property and other taxes related to the operation of the unit, expected capital additions, any other expected cash expenditures, as well as the appropriate discount rate (cost of capital). The development of stranded costs using this approach would require that the expected net cash flow from the sale of power from each asset (a function of sales volumes, market price and cash cost) be determined over the remaining life of the asset and then present valued using an appropriate discount rate. The difference between the net present value of the cash flow so determined and the book value of the asset would be a measure of the strandable costs.

When this approach is applied, it is necessary to look at the generation resources on a unit by unit basis in order to screen out the effects of any units where the going forward costs exceed the value of the sale of energy in the market. That is, if the going forward cost of the unit exceeds market price, costs can be minimized by shutting down the unit and not operating it, rather than by operating the unit and incurring net out-of-pocket expenditures.

In contrast, administrative methods using a "top down" approach focus on the overall revenue levels of the utility instead of the value of the individual generating assets as the source of the stranded cost calculation. This type of analysis uses estimates to compare the amount of revenues a utility would have received under traditional regulation with the amount to be received under competitive conditions. The difference in the two amounts would be "lost revenues," which could be recouped through a stranded cost charge. It is important to understand that a top down or lost revenues approach to measurement of stranded costs is still dependent upon assumptions about the ability of a utility's generating assets to remain competitive in a retail access environment. Unlike a bottom up approach, such assumptions are not made in an explicit manner, but are instead made in a simplified fashion.

Administrative determinations of stranded costs are likely to result in complex, highly contested regulatory proceedings. Given the inherent subjectivity of the assumptions entering into the calculation, it is reasonable to foresee wide divergence among the parties to stranded cost proceedings as to the recommended amount of stranded cost recovery. Also, regulators' traditional inability to accurately forecast utility avoided costs demonstrates that administrative forecasts of electric utility economic parameters, taken by themselves, are unlikely to yield accurate results.

Recognizing the inherent uncertainty in many of the forecasts, the risk of error can perhaps be reduced by future "true-ups" or "sanity checks" on the initial forecast. This approach would apply a "new look" from the point of examination to the end of the life of the asset being evaluated. New values for market price would be determined based on more current information, and experience with respect to cost reductions and improvements in efficiencies by the utility operating the asset and changes in sales volume would also be incorporated. To the extent that the Commission had specified cost reduction targets for the utility, they would be incorporated into the valuation equation. While this approach helps overcome some of the more fundamental data problems inherent with an administrative evaluation, it must be recognized that at any point in time when a true-up is performed, there still must be a forecast of all relevant parameters over the remaining life of the asset. The risk of forecast error in an administrative approach cannot be eliminated at any point in time during the life of the asset. Further, a failure to continue to forecast to the end of the life of the asset could result in a biased approach wherein customers would have paid all upfront costs when costs exceed market value, but would not enjoy the benefits later on when costs would be less than market prices.

Regarding top down approaches to calculating stranded costs, it is an error to assume that all revenues that may be lost as a result of competitive access should be recoverable through a stranded cost charge. For example, part of a utility's existing revenue base is related to the variable costs of operating its generating units. Such costs may be reduced by ongoing efforts by a company to operate its plants in a more efficient manner, or may be eliminated in entirety by shutting down the unit in question. Under such a circumstance, a utility receiving stranded cost recovery based on the lost revenues approach would be the beneficiary of subsidies that provide compensation for variable plant operating costs that it no longer incurs. The same logic applies to other costs included in regulated rates that could be reduced or avoided by utilities in a competitive environment. For this reason, the only generation plant costs that could be potentially strandable costs are the sunk, fixed, capital costs associated with existing generation assets, plus truly unavoidable operating costs, if any.

Before turning to a discussion of the various quantification methods that have been used or are being considered for use in other jurisdictions, it should be mentioned that few quantification methods are purely administrative or purely market-based. While sale/spin-off methods of quantifying stranded costs for generating assets directly rely on market valuations created by third party transactions to value stranded costs, other techniques sometimes referred to as market methods use proxy "market" valuations of assets to value stranded costs, while leaving ownership of the asset in question unchanged (i.e., "appraisal" quantification methods). On the other hand, administrative methods can rely to some degree on market values measured or used by the individuals estimating the stranded cost amounts. Some of the methods discussed herein could be regarded as "combination" methods, reflecting aspects of both market and administrative approaches.

The next section will discuss certain stranded cost methodologies, starting with those considered more market-based, and ending with those considered more administrative in nature.

C. Mechanisms for Quantifying Stranded Costs

Several market or "combination" (reflecting both an administrative approach and an element of market information) mechanisms for quantifying stranded costs have been proposed in the electric industry restructuring debates that are taking place across the country. These mechanisms include:

- Asset sales to third parties through an auction or a negotiated sale;
- A spin-off, or a spin-down, of generation assets into a separately traded entity;
- An independent appraisal of the market value of generation assets;
- A solicitation, or reverse solicitation, for competitive power supplies;
- Use of a market price index to establish competitive power prices; and
- Independent determination of market price.

The first two listed methods (asset sales and spin-off/spin-downs) are pure market approaches which result in a market value for the asset in question being determined, and ownership of the asset in question changing hands in the course of an arms-length transaction. The independent appraisal method results in a market value approximation for the asset, but ownership of the asset does not change hands. Along with the independent appraisal method, the last three listed approaches are more in the nature of "combination" methods; they are technically administrative-type approaches involving numerous assumptions, but with explicit provisions for incorporation of certain market information relating to the market price of electricity into the stranded cost calculation.

Each of these market or combination mechanisms has its advantages and drawbacks. While most of the quantification methods contemplated above have few, if any, precedents in the U.S. electric industry, this paper will discuss any practical applications of these market-type mechanisms to date that are relevant to the quantification of stranded costs.

Several public utility commissions have issued orders in causes where administrative-based methodologies have been contested. Results for the following categories of administrative proceedings are also briefly recounted:

- Bottom-up administrative
- Top-down administrative

1. <u>Auction or Negotiated Sale</u>

The most direct market mechanism for quantifying stranded costs is through arms-length, competitive asset sales to third parties. Under this approach, the stranded costs associated with the sold assets would be determined by offsetting the sale price of the assets against their net book value. These assets sales could be accomplished either through private negotiations with potential purchasers or through an open auction process. This market mechanism is attractive in that it establishes a market price for individual utility generation assets. Utility purchased power contracts could be auctioned or sold in a similar fashion to determine any stranded costs that might be associated with them.

An auction of generation assets is the most frequently applied market mechanism for quantifying stranded costs that has been proposed to date in the U.S.[4] This method is being implemented by Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) in California, the New England Electric System (NEES), COM/Electric, Eastern Utilities Associates, and Boston Edison Company in Massachusetts, and by Central Maine Power Company and Maine Public Service Company in Maine, among others. In New York, Con Edison has also committed to sell one-half of its generating capacity in New York City. In California, San Diego Gas & Electric Company recently decided to auction its two fossil-fired power plants.

While there are differences in the conduct of each utility asset auction, the basic auction processes proposed by the above referenced utilities are similar in most respects. In the initial stage of the process, the utility sends out letters to a wide range of national and international electric utilities, energy companies, independent power producers, power marketers, private power developers, financial institutions, electrical equipment manufacturers, and other potential buyers of the utility's assets. These letters provide a basic description of the auction process and the assets to be sold. The utility then pre-qualifies potential bidders who indicate interest in its plant auction. These pre-qualified bidders are sent a more detailed offering memorandum and asked to submit initial offers for the assets by a date certain. Interested bidders are then required to submit initial, sealed bids containing a specified price level or an acceptable price range for individual assets or asset groupings.

---

[4]Generally, where divestiture methods have been used to quantify stranded costs, market power concerns were also instrumental in the legislature and/or regulatory agency ordering or encouraging use of the divestiture approach.

The selling utility then reviews the bids and selects a number of first round bidders who qualify for the second round of bidding. The utility sends qualifying second round bidders further information on each of its generation plants and gives them the opportunity to conduct their own due diligence reviews of the assets, including on-site presentations on the power plants. The second round bidders are then required to submit final bids for their selected assets. If the final bids differ from the initial bids, the utility typically requires the bidder to specify the economic, technical, and other considerations that led to a revision of the bid. In the final stage of the auction, the utility selects the winning bidder(s), signs sales contracts for the assets, and submits these contracts to the appropriate regulatory commission for review and approval of the asset sales.

An auction process is generally more desirable from the customer perspective than a privately negotiated asset sale because the auction process attempts to increase the amount of competition to purchase an asset, thereby maximizing the asset's price. However, there are several factors relating to the design of a competitive auction that can significantly influence the resulting asset prices.

One concern pertains to whether the selling utility will directly participate in the auction. Because many utilities in the U.S. are reluctant to contemplate generation asset divestiture, jurisdictions such as California and Texas have considered the possibility of conducting asset auctions in which the selling utility would be allowed to participate in the auction, either directly or through an affiliate, and retain a right of first refusal to match the bids of other parties, thereby giving the utility the opportunity to retain ownership of its generation assets while accomplishing a market-based quantification of the utility's stranded costs. The risk is that right of first refusal auctions could depress asset prices by reducing participation in the auction and causing participants to discount their bids for assets. Of course, another option is that selling utilities could be given the right to submit bids for their own assets, without also being given the right of first refusal.

Another important issue in the design of asset auctions is whether the assets are sold individually or in groupings. In California, SCE proposed to group its auctioned generation assets into bidding bundles. This procedure effectively restricts the ability of bidders to purchase assets individually.[5] By contrast, PG&E designed its auction to give bidders the flexibility to bid on

---

[5]Southern California Edison, Application of Southern California Edison for Authority to Sell Gas-Fired Electrical Generation Facilities: Description of the Proposed Auction Process, California Public Utilities Commission, November 1996, p. 13.

individual assets or asset bundles of their own choosing.[6] In New England, NEES allowed potential buyers to bid on three different generation packages: (1) its non-nuclear generation assets as a whole, (2) its fossil fuel plants as a bundle, and (3) its hydroelectric plants as a bundle. NEES also hopes to sell its ownership interests in regional nuclear plants through a separate process.[7]

Given the paucity of practical experience with generation asset auctions, it is difficult to assess whether the use of bidding bundles will enhance or depress asset values. On the one hand, the sale of asset bundles could enhance asset values by giving buyers the opportunity to take advantage of synergies and operational efficiencies associated with joint ownership of certain generation assets. For example, SCE grouped its gas-fired plants into asset bundles based on geographic proximity, thereby allowing buyers to realize savings through the sharing of inventories, maintenance personnel, and supervisory staff among the plants in each bundle. SCE also asserted that sale of its generation assets in bundles would reduce the likelihood of thin bidding for particular plants, which might occur if bidders are forced to allocate their finite time and resources among several, simultaneous, individual plant auctions. Finally, SCE stated that the sale of its generation assets in bundles, rather than individually, would reduce the transaction costs of conducting the auction and accelerate the timetable for divestiture.[8]

While the use of bundles can produce certain benefits that enhance asset values, particularly through the synergies created by common ownership of multiple plants, it is also possible that the forced sale of assets in bundles could depress total auction proceeds by eliminating the ability of bidders to purchase individual assets. Based on their own assessments of plant and market characteristics, certain bidders might be willing to pay a price premium for specific power plants that they might not be prepared to pay if they were forced to purchase a particular plant as part of a larger asset bundle. Of course, it is always possible to design an auction in a manner that grants bidders the flexibility to bid on individual assets or asset bundles of their own design. It appears that such

---

[6]Pacific Gas & Electric, Pacific Gas And Electric Company's Testimony Supporting Authorization To Sell Certain Generating Plants And Related Assets Pursuant To Public Utilities Code Section 851, California Public Utilities Commission, November 1996, p. 2-4.

[7]Electric Power Alert, NEES Generation Auction Lures 25 Bidders To Snap Up Fossil Generation, April 9, 1997, p. 13.

[8]Southern California Edison, Application of Southern California Edison for Authority to Sell Gas-Fired Electrical Generation Facilities: Description of the Proposed Auction Process, California Public Utilities Commission, November 1996, pp. 15-18.

a flexible auction process would be the best method of maximizing auction revenues. Apparently accepting this logic, the CPUC recently ruled that SCE must allow bidders in its asset auction to submit bids on any combination of plants in the auction.[9]

Another major issue in the design of asset auctions is whether asset sales should be conducted simultaneously or phased-in over time. Some analysts are concerned that simultaneous asset sales representing large quantities of generation capacity could result in "fire sale" prices by creating a glut of generation available for sale in a regional market. Obviously, such an eventuality would artificially inflate a utility's stranded cost levels if an auction process is used to quantify the utility's stranded cost exposure. On the other hand, it can be argued that conducting an asset auction simply transfers ownership of generation among market participants, rather than changing aggregate supply and demand levels for power. In this view, so long as aggregate supply and demand levels remain constant, simultaneous auctions of multiple generation assets are not likely to depress asset values.[10]

2. Nuclear Asset Auctions or Negotiated Sales

In the case of nuclear assets, many analysts are concerned that the risk of future changes in regulations, such as nuclear safety and decommissioning requirements, is so large that it will result in massive discounting of nuclear asset market values or eliminate the possibility of selling nuclear plants altogether. The regulatory risks associated with nuclear plant ownership were underscored by the Nuclear Regulatory Commission's (NRC's) recent policy statement on electric industry restructuring. In that statement, the NRC indicated that it will impose more stringent decommissioning requirements on unregulated electric companies that acquire nuclear assets. Such requirements could include full, up-front funding or some form of guaranteed payment of estimated decommissioning costs. Moreover, the NRC stated that it reserves the right to impose joint and

---

[9]California Public Utilities Commission, In the Matter of the Application of Southern California Edison (U 338-E) for Authority to Sell Gas-Fired Electrical Generation Facilities, Interim Opinion, Decision 97-09-049, September 3, 1997, p. 18.

[10]Jonathan Lesser and Malcolm Ainspan, Using Markets to Value Stranded Costs, *The Electricity Journal*, October 1996, pp. 72-73.

several liability on the co-owners of nuclear plants if one or more co-owners defaults on its obligation to pay for plant operating and decommissioning expenses.[11]

These NRC policies impose substantial risks on potential buyers of nuclear assets. In addition, prospective buyers would be exposed to the risk that even more stringent regulatory requirements could be imposed in the future, thereby reducing the value of their nuclear assets.

While there have been some recent expressions of interest to purchase nuclear facilities in the United States, to date no such efforts have succeeded. It is likely that the sale of nuclear assets can be made more attractive in the marketplace if an effort is made to minimize the regulatory risks faced by potential buyers. For example, potential buyers may have more interest in marketing a nuclear plant's output than purchasing the asset outright. Buyers might be willing to assume some operational risks associated with nuclear facilities if they can avoid the decommissioning risks that come with plant ownership.

Such a separation of risks could be accomplished by requiring the selling utility to retain responsibility for a fixed percentage or dollar amount of a nuclear plant's future decommissioning costs. Consistent with the electric industry restructuring agreements negotiated to date in the U.S., the selling utility's share of plant decommissioning costs, or a portion thereof, could then be included in its stranded cost assessment to customers in its traditional service territory.

The value of distributing risk in marketing nuclear assets is reinforced by the United Kingdom's experience in privatizing its nuclear industry. The Thatcher Government was able to accomplish this privatization in the Summer of 1996 by floating the shares of a newly created, publicly traded nuclear utility, British Energy, on the London stock exchange. The success of this privatization effort was, in large part, due to the British Government's willingness to retain many of the operating and decommissioning risks associated with the U.K.'s nuclear fleet. Specifically, the British Government retained ownership of the oldest nuclear plants that were nearing the end of their economic life, and negotiated fixed price contracts with British Energy for nuclear waste

[11]Nuclear Regulatory Commission, Final Policy Statement on the Restructuring and Economic Deregulation of the Electric Utility Industry, 10 CFR Part 50, August 13, 1997, pp. 10, 11, and 13.

disposal services. This arrangement reduced the risks associated with nuclear plant ownership to a level that was sufficient to allow for successful nuclear privatization.[12]

Obviously, the U.K.'s experience differs from that of the U.S. in that American commercial nuclear assets are privately owned. Therefore, the U.S. does not have the same degree of flexibility that the British Government enjoyed in managing nuclear risks. Nevertheless, appropriate risk sharing arrangements between private entities could facilitate the sale of nuclear assets in the U.S.

3. Analysis of Auction Results

Although an asset auction is the most popular market mechanism for quantifying utility stranded costs that has been implemented to date in the U.S., there is very little empirical evidence regarding the actual performance of these auctions in valuing utility assets. This is the case for two principal reasons. First, many of the auctions conducted in the U.S. are still in progress. Therefore, the final auction results are not yet available. The selling utilities in these auctions are reluctant to release initial bid results, including the identities of bidders, for fear of distorting the ultimate outcome of the auction. Second, concerns for the confidentiality of competitively sensitive information, both on the part of sellers and buyers, make it difficult to obtain information regarding bid offers or final auction prices for individual generating units. Although the aggregate auction proceeds should ultimately be made public because they will be used to quantify utility stranded costs, it is not clear whether the winning bids for individual units will eventually be publicized.

One factor that should be mentioned with regard to the valuation of utility stranded costs through asset sales is that most utilities are extremely reluctant to engage in such sales, both because they are generally resistant to structural unbundling of their operations and because they do not desire to sell their generation assets to potential competitors. While some utilities across the nation have been very aggressive in rapidly restructuring their companies for retail competition, those not in favor of competition are likely to strongly oppose attempts to quantify their stranded cost exposure through an asset auction or other means that result in asset divestiture.

It is debatable whether regulatory or even legislative bodies have strong legal authority to require the divestiture of generation assets. Because electric utility bonds have typically been backed by the combined assets of the vertically integrated utility, structural separation of integrated utilities

---

[12]Kahn, Edward P., Can Nuclear Power Become an Ordinary Commercial Asset?, *The Electricity Journal*, August/September 1997, pp. 19-20.

through asset sales or other means also creates potentially complicated bond indenture problems that must be resolved. Therefore, it may be difficult to impose mandatory divestiture of generation assets.

The generation asset auctions contemplated or initiated to date in the U.S. are the result of regulatory and legislative actions, as well as restructuring agreements, designed to induce voluntary asset divestiture, generally in exchange for guarantees of stranded cost recovery and other concessions to utility interests in the process of restructuring the electric utility industry in various states.

As previously discussed in the Definitions section of this report, it is probable that most (if not all) of the potential stranded costs in Missouri are associated with the Callaway and Wolf Creek nuclear units. Given the potential difficulties described herein in auctioning off nuclear assets, it is likely that any generating units that may be subject to auction in Missouri in the near future will be fossil fuel units, with net negative stranded costs overall rather than positive stranded costs. Under this scenario, therefore, auctions would not be used in Missouri to directly quantify the stranded costs of those generating assets most likely to give rise to positive stranded costs, but instead would be used to quantify an amount of potential negative stranded costs to offset against the nuclear units' positive stranded costs (presumably quantified by some other means).

4. Spin-Off or Spin-Down of Generation Assets

Another market mechanism for quantifying stranded costs is through a spin-off or a spin-down of a utility's generation assets. Under this method, stranded costs are quantified through a stock valuation when the utility spins-off its generation assets into a separate, publicly traded, non-affiliated corporation. The market price of the assets would be determined by using the average daily closing price of the stand-alone generation company's common stock over a specified period of time. Alternatively, the CPUC has suggested that the market price of the spun-off assets could be determined based on changes in the stock price of the original company which spun off the assets.[13] In either case, the utility's stranded costs would then be determined by offsetting the stock price against the net book value of the utility's generation assets.

[13]California Public Utilities Commission, Docket Nos. R.94-04-031 and I.94-04-032, Order Instituting Rulemaking and Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, Decision No. D.96-01-009, January 10, 1996, p. 130.

A spin-down mechanism involves essentially the same procedure described above. However, in a spin-down, the utility separates its generation assets into an unregulated affiliate, and distributes new shares of stock in the unregulated affiliate to its existing shareholders. The new affiliate's stock is then independently traded. Thus, a spin-down can accomplish a market-valuation of stranded costs without requiring complete generation asset divestiture. Also, under either a spin-off or a spin-down, the proceeds of the transaction will generally not be taxable, unlike the situation with asset sales.

A spin-off is one of the most widely discussed means of achieving a market valuation of utility stranded costs. In fact, this mechanism was cited in California's restructuring legislation as one of the divestiture options available to the state's major utilities.[14] An asset spin-off has many precedents in various U.S. industries, including the utility sector. The spin-off of Lucent Technologies by American Telephone and Telegraph is perhaps the most widely publicized recent example of this divestiture strategy.

However, this mechanism has yet to be implemented in the electric utility industry. In practice, those utilities facing a choice as to divestiture procedures have chosen to divest themselves of generation assets using an open auction process rather than a spin-off. Are there disadvantages to a spin-off that make this option less attractive than an asset auction?

First, an auction could produce higher asset prices than a spin-off because buyers might be willing to pay a "control premium" for the direct purchase of individual assets. A spin-off would result in the creation of a publicly traded company owned by numerous shareholders. Therefore, one entity would be unable to exclusively control the operation of an asset.[15]

Second, a spin-off can complicate the valuation of assets by introducing factors that do not pertain directly to the intrinsic value of the generation assets being sold. For example, investor perceptions regarding the quality of a newly created generation company's management could influence the new company's stock price. Investors might also attribute more risk to a newly created, stand-alone company simply because it has no operating history. Such perceptions could lead investors to discount the value of the new company's assets. A market valuation based on a spin-off

---

[14]*See* General Assembly of California, Assembly Bill 1890, August 1996.

[15]Southern California Edison, Application of Southern California Edison for Authority to Sell Gas-Fired Electrical Generation Facilities: Description of the Proposed Auction Process, California Public Utilities Commission, November 1996, p. 7.

can be further complicated if the spun-off company holds assets other than generation assets. In such a case, the market's valuation of the non-generation assets is likely to be factored into the new company's stock price. It can be argued that the consideration of such factors is not directly related to the inherent market value of the generation assets themselves. As a result, the value of utility assets could be captured more directly through an open auction.

Another complication with the use of a spin-off to quantify stranded costs is that the spun-off company's stock price is likely to fluctuate over time. Therefore, a "snap-shot" assessment of the newly created company's initial stock valuation might not accurately reflect the true market value of the underlying generation assets. This problem is exacerbated in the case of a spin-down because the initial stock valuation of the new affiliate would be determined by the holding company's management when it distributes the affiliate's stock among its shareholders. However, this problem can be remedied by using the average stock price of the spun-off company over a sufficiently long period of time as the market price of the underlying assets for stranded cost quantification purposes. This approach would be more likely to reveal the true market value of the utility's assets.

As is the case with a bundled asset auction, a spin-off can facilitate the divestiture of nuclear plants at reasonable prices by spreading the nuclear asset risk among a wide variety of generation technologies that are sold as a group. Thus, it might be more feasible to persuade investors to purchase shares in a stand-alone generation company that owns one or two nuclear assets than it would be to persuade a company to purchase an individual nuclear asset.

5. Asset Appraisal

Another quantification mechanism with some attributes of a market approach is an independent appraisal of the utility's generation assets. While this valuation option was included in California's restructuring legislation, it has not yet been implemented in practice to quantify stranded costs.

To implement this option in California, the CPUC suggested that industry stakeholders submit an agreed-upon list of impartial and qualified asset appraisers, from which the CPUC would select no more than three to value a utility's assets. The results of the appraisal would then be used to quantify the utility's stranded cost exposure. If the utility rejected the appraisal, it would then be required to spin-off, or sell, the assets. In addition, the CPUC reserved the right to review and approve the appraisal to ensure that the utility did not improperly reject an appraisal and then receive a lower sale price, an eventuality that would increase the utility's total stranded costs.[16]

The major advantage of the appraisal approach is that it provides a means of arriving at a market valuation of a utility's assets without requiring asset divestiture. Thus, this option is likely to be more palatable to most utilities. An asset appraisal can also be considered superior to an administrative quantification in that the valuation relies on the opinions of independent industry experts, as opposed to the testimony of experts hired by the parties to a contested proceeding.

The use of independent experts to appraise the utility's assets could reduce litigation surrounding the quantification of utility stranded costs. However, this reduction in litigation might not materialize if the regulatory commission uses its approval process to second-guess the appraisal results. If this were to take place, then the appraisal would be effectively transformed into an administrative quantification of stranded costs.

In addition, the dearth of price comparables from other generation asset auctions would make it difficult to assess whether the appraisal resulted in a reasonable market value for an asset. Currently, there are very few completed generation asset auctions in the U.S. that an appraiser could use as a measure of a particular asset's market value. This absence of price comparables introduces a significant element of speculation into the appraisal process.

Finally, an asset appraisal is not truly market-based because it does not rely on the interaction of buyers and sellers in a competitive market to arrive at an asset's value. It is much easier for a regulatory commission to second-guess an appraisal that is conducted in the abstract than it is to nullify the results of a completed asset auction or spin-off. Therefore, the appraisal mechanism does not produce the definitive market valuation of utility assets that is the most desirable feature of truly market-based quantification mechanisms.

6. Power Solicitation or Reverse Solicitation

An additional market mechanism for quantifying stranded costs is a direct solicitation or reverse solicitation for power. In a direct solicitation, the utility requests proposals for a given quantity of capacity and energy from competitive providers. In a reverse solicitation, the utility

---

[16]California Public Utilities Commission, Docket Nos. R.94-04-031 and I.94-04-032, Order Instituting Rulemaking and Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, Decision No. D.96-01-009, January 10, 1996, pp. 131-132.

auctions a block of capacity and energy in the open market. In either case, the winning bid for the block(s) of power determines the market price for electricity. This market price is then used, along with assumptions about operating costs and characteristics, to calculate a utility's stranded costs. Consumers Energy has proposed to auction off the capacity from its non-utility generator contracts, on an annual basis, to establish a market price for power that can be used to true-up its stranded cost calculation in future years.[17]

The major advantages of the solicitation approach are that it is fairly easy to administer and it does not require asset divestiture or other restructuring of the utility's operations. These features make a solicitation desirable to many utilities, and perhaps to regulators who do not wish to address the issue of asset divestiture.

However, the central weakness of the solicitation approach is that it produces a market price for *power*, not for utility *assets*. Therefore, critical assumptions still must be made to translate this power price into a stranded cost valuation. Needless to say, each of these assumptions has a significant impact on the amount of a utility's stranded costs.

The first major assumption made in the solicitation approach is that the solicitation results provide a true indication of the regional market price for power. However, this is not necessarily true. Any solicitation will be designed to purchase or sell a certain quality of power for a designated period of time. This solicited power block represents only one type of power that is available in competitive power markets.

Markets attach varying prices to different qualities and types of power. For example, firm power is typically more expensive than non-firm power. Similarly, the average price of spot market energy is often less than the price of a three-year, fixed price contract because purchasers of fixed price contracts are often willing to pay a premium for price certainty. Therefore, it is questionable whether a solicitation for one or two blocks of power can yield a market price that adequately reflects the composite value of the different types and qualities of power that can be sold by a utility's power plants in competitive markets. It might be necessary to auction off several different blocks of power, reflecting a range of capacity factors in order to mirror the expected operating characteristics of base load, cycling and peaking units.

---

[17]Electric Utility Week, Consumers Energy To Use Auction Of NUG Capacity To Determine Stranded Costs, July 21, 1997, p. 15.

Another variable in the process is the length of the contractual obligation. The price that purchasers would be willing to pay for obligations of three years, five years, ten years, etc., will likely be different. It would seem appropriate that the contractual obligation commit the seller to sell, and the purchaser to purchase, the contractual quantity of power over a period somewhat representative of the life of the underlying assets that are being evaluated.

Moreover, the solicitation approach assumes that a power auction conducted in today's market environment will yield a market price that is representative of future prices in competitive retail markets. This is an unproven and debatable assumption. Prices in regional power markets are likely to increase as existing excess supply is absorbed by growing demand for electricity. In addition, it is possible that the advent of retail access will ultimately create upward pressure on power prices by introducing a large number of new buyers into power markets. Thus, there is a great deal of uncertainty regarding the future pattern of competitive power prices. Therefore, a solicitation conducted under today's market conditions might yield power prices that are significantly different from the regional market clearing prices that will prevail after the advent of retail access. If this proves to be the case, the solicitation mechanism will not accurately quantify a utility's stranded costs.

Concerns regarding the timing of the power auction can be mitigated by conducting the auction after retail competition is introduced in the relevant market area. However, the timing of the auction remains significant even if the power sales take place in a fully competitive environment. For example, the power auction could be conducted while the regional power market remains in an excess capacity situation. This would likely result in lower power prices relative to the price levels that would be observed once excess generation capacity in the region is absorbed.

In order to translate the power prices resulting from a solicitation into a stranded cost valuation, additional assumptions must be made. The solicitation approach is premised on the notion that a utility's assets should be valued based on the estimated profit margins that its power plants are likely to realize in competitive markets. While this presumption is basically accurate, the difficulty with the solicitation approach is that the key parameters which drive the expected profit calculation are based on administratively determined assumptions.

In a truly market-based asset valuation, potential purchasers of the asset make their own independent judgments regarding projected power prices and plant operating characteristics. The bidders who see the most profit potential in the asset will bid the highest prices. By contrast, the solicitation approach requires regulators to specify the critical cost parameters that are used to value the utility's assets.

For example, the solicitation method makes critical assumptions regarding plant capacity factors and future operating costs. If the assumed capacity factors are too low or the operating cost projections are too high, the utility's assets will be undervalued, thereby increasing the magnitude of its apparent stranded costs. Therefore, use of a solicitation, or reverse solicitation, mechanism can produce adverse results unless the regulator can be persuaded to adopt appropriate assumptions for the critical parameters that drive the asset valuation. Due to the information advantage enjoyed by the utility regarding the potential performance of its own assets, this goal might be difficult to accomplish.

7. Market Price Index

Another potential method to achieve a market-based valuation of stranded costs is to rely on a recognized market price index to establish the market price for electricity. This method has been proposed by Detroit Edison in Michigan to true-up its stranded cost calculation in future years.[18] Established market price indices for electricity are evolving for various trading hubs around the country. For example, the trade publication *Power Markets Week* currently compiles price indices for many geographic regions. Such indices could be used to establish a market price for electricity that would form the basis for a market valuation of assets.

The advantages and disadvantages of using a market price index are similar to the ones cited for the solicitation approach. On the positive side, this mechanism is relatively easy to administer, relies on objective market price data, and does not require asset divestiture to quantify a utility's stranded costs.

On the negative side, market price indices are generally based on spot energy prices. Therefore, they do not appropriately reflect the market price of the various types and qualities of power that are likely to be sold in competitive retail markets. Because spot energy prices are typically lower than the prices of other competitive power contracts, the exclusive use of spot energy to measure market prices is likely to increase the magnitude of stranded costs.

---

[18]The Detroit Edison Company, Proposal For Annual True-Up Mechanism, Michigan Public Service Commission, Case No. U-11290, July 9, 1997, p. 6.

As is the case with the solicitation approach, critical assumptions regarding the capacity factors and cost characteristics of the utility's power plants must be made to translate the indexed power prices into competitive asset values. If these assumptions are inappropriate, they are likely to result in inflated stranded cost estimates.

8. Independent Determination of Market Price

Restructuring legislation recently passed in the state of Illinois[19] includes a methodology for estimating market price as a part of the on-going compensation to the utility for stranded costs.[20] The Illinois legislation calls for the use of indexes to determine market price, but only if and when reliable and representative indexes are available. In the meantime, the legislation establishes the concept of a "Neutral Fact Finder" or NFF. The NFF would be selected by the Illinois Commerce Commission based on a set of criteria specified in the statute. A new NFF would be selected every year. The NFF would receive copies of all power contracts for sales of power into Illinois, and all contracts for sales from Illinois-based generation to out of state purchases. The NFF would prepare from this information a series of market prices based on factors such as time of use, degree of firmness, voltage level, contract length, and other parameters that influence price. This approach has the advantage of an independent determination of the market price of power, but the disadvantage of placing reliance upon a single individual.

9. Bottom-up Administrative Determination

At least one jurisdiction has considered stranded cost quantification issues in the context of competing administrative calculations produced by various market simulation models. In Pennsylvania, the public utility commission was faced with determining PECO Energy's level of

[19]Illinois State Legislature, "Electric Service Transition and Customer Choice Law of 1996." (Passed by the Senate and House in October and November 1997 and signed into law by the Governor on December 16, 1997.)

[20]Under the Illinois legislation the stranded cost compensation is effectively equal to the embedded cost of generation that is collected in tariff or contract rates, minus the market value of power and energy, minus a mitigation factor which begins at 5 mills per kilowatthour and ramps up.

stranded costs in proceedings that just recently concluded.[21] The Pennsylvania Commission considered a myriad of issues concerning PECO's stranded cost quantification. Among the items at issue were the results of market simulations determining the market value of PECO's generating assets and contracts. PECO introduced no less than three market studies that indicated its expected asset valuation per the market ranged from \$2.86 billion to \$3.65 million. (By the end of the proceeding, PECO reduced its lowest estimated market valuation amount to \$1.865 billion.) Most of the other parties' studies indicated market values for PECO's generating assets that were considerably higher. The Pennsylvania Commission indicated that PECO's multiple studies were contradictory and produced results that were materially different. Accordingly, they selected another party's valuation of \$3.96 billion.

Also disputed was the appropriate cost of capital rate to use in the stranded cost calculations. PECO argued for its after-tax cost of capital, while the commission instead allowed PECO's current long-term debt rate. Finally, while the PECO settlement rejected by the Commission did not reflect any true-up or reconciliation of stranded cost collections, the Commission's Order called for an annual reconciliation.

10. <u>Top-down Administrative Determination</u>

In New Hampshire, the restructuring legislation passed there required the public utility commission to set "interim" stranded cost charges. To that end, the commission took evidence on the expected future market price of electricity in the New England area from interested parties, including utilities, industrial customers, consumer advocates and its Staff. The estimates varied widely; from 2.5¢/kWh to 4.58¢/kWh for the 1998 market price. These prices reflected both energy and capacity components. The different market price estimates resulted from differing evaluations and weights given to the following factors: the timing and type of new capacity to be introduced to the New England area to meet incremental capacity needs, expected fuel escalation rates, and the relevant wholesale transaction prices to be incorporated into the analysis, among other factors. The New Hampshire Commission chose an expected market price of 4.14¢/kWh in 1998, based on an

---

[21] Application of PECO Energy Company for Approval of Its Restructuring Plan under Section 2806 of the Public Utility Code and Joint Petition for Partial Settlement (R-00973953) and Petition of Enron Energy Services Power, Inc. for Approval of an Electric Competition and Choice Plan and for Authority Pursuant to Section 2807(A)(C) of the Public Utility Code to Serve as the Provider of Last Resort in the Service Territory of PECO Energy Company (P-00971265), Opinion and Order of the Pennsylvania Public Utility Commission dated December 11, 1997.

energy cost estimated from average system marginal energy cost derived from hourly energy bids into the NEPOOL ISO. The capacity cost included in the 4.14¢ price reflect new combined cycle gas units and combustion turbines to meet incremental capacity needs.

The other notable top-down administrative method approved to date by a regulatory commission is the "lost revenues" approach ordered by the Federal Energy Regulatory Commission (FERC) in Order 888. FERC's desire is to assign stranded costs directly to the utility's departing wholesale customer. (This approach is easier to take with wholesale customers, who are generally larger and whose service requests sometimes require discrete plant additions by the serving utility, than it is with the mass of retail customers of the utility.) The stranded costs are defined as the difference between the utility's expected revenues from the departing customer and the market value of the capacity and energy freed up by that departure. The assumed revenue lost is calculated as the average sales to the customer for the three prior years before the departure. The market value of the freed up energy and capacity is determined by the utility, though the departing customer may replace that value by the market price it struck with the competing supplier, if it chooses to. The departing customer also has the right, under some circumstances, of marketing or brokering the released power resulting from its departure, if it believes the utility's market value estimate is too low.

FERC's method does not include true-ups or reconciliations, as it believes the certainty of determining a fixed stranded cost value outweighs the increased accuracy associated with true-ups.

The legislation recently passed in Illinois also provided for a "revenue lost" method of calculating allowable stranded cost recovery, but refrains from estimating the level of stranded costs; using instead a mandated mitigation of stranded costs.

D. True-ups

"True-ups" (also known as "reconciliations") are simply a one-time only or periodic revisiting of an initial stranded cost calculation. Based on later or more relevant information, true-ups allow stranded cost estimates to be corrected so that there is less chance of the utility over- or under-collecting, and conversely of the customer under- or over-paying. Stated in these terms, use of true-up would seem to be non objectionable, or even essential, to the stranded cost process. However, use of true-ups in actuality brings up a number of policy questions for decision-makers to consider.

The first thing to keep in mind is that true-ups are rarely used in current regulation in Missouri. When a Commission sets rates for a utility, the rates are based on a representative level of revenues, expenses and rate base for that utility. If these levels are not representative of the actual revenues, expenses and rate base in the period new rates are in effect, then the rate levels will be "incorrect" and the utility will either overearn or underearn. The utility shareholders are fully responsible for the over- or underearning, and either enjoy the incremental income or suffer a deficit until new rates levels can be set in response to the changed revenue, expense, and rate base levels. There is no true-up mechanism employed in normal regulation to make utilities whole for past underearnings, or to reimburse customers when utilities overearn.

The fact that utilities are at risk for earning a reasonable rate of return as set by commissions is what requires their authorized rate of return to be considerably above the return associated with risk-free treasury bonds, for example. Also, the fact that utilities are "at risk" for revenue reductions, expense increases, or increases to rate base is the biggest incentive utilities currently have to maintain or increase their productivity and efficiency over time. Therefore, use of true-ups to reconcile stranded cost recovery by utilities would be a significant departure from normal ratemaking practices.

Further, it should also be recognized that true-up procedures can be used for vastly different purposes. For instance, true-ups can either be a "mid-course correction" or be used as a "make whole" provision. Using true-ups as a mid-course correction means recalculating the stranded cost value for a utility, and allowing that utility to increase or decrease its charge prospectively to reflect the new result. But, the utility would not be allowed to recoup past undercollections or give back past overcollections based on the new, corrected stranded cost amount. In contrast, use of true-ups as make whole provisions means not only using the new calculation of stranded costs as the appropriate value for ongoing purposes, but also adjusting the rate to reflect past over- and under-collection of stranded costs. The policy implications of using true-ups in these differing manners is quite significant.

True-ups are more commonly associated with administrative stranded cost quantification methods than with those that are more market-based. This is because direct market valuation approaches (sale, spin-off) reflect an outside entities' perception of the market value of an asset or group of assets, and the outside entity (the purchaser) assumes the risk that their market value estimates will later be found to be incorrect. In contrast, when administrative methods are used, either the utility or its customers, or both, will bear the risk of inaccurate stranded cost estimations. All of the "combination" valuation methods discussed earlier can be subject to true-up if desired. However, particularly for the independent appraisal method, if one accepts their results as a reasonable proxy for market values for the assets in question, there is probably no compelling reason to do a later reconciliation of stranded cost amounts.

Following is a series of arguments for and against use of true-ups for purposes of reconciling stranded cost collections.

1. Arguments for True-ups

The most compelling argument for truing-up stranded cost calculations is the risk of initial inaccuracies in such calculations. As previously discussed, stranded costs as determined by administrative methods are dependent upon assumptions about a wide range of factors. In particular, the market cost of power is one variable where it is doubtful that there will be upfront agreement by all parties. In situations where public utility commissions have considered administrative calculations of stranded costs from a variety of sources, the result has been a wide range of estimates, generally with pro-stranded cost recovery parties estimating more stranded costs, and anti-stranded cost recovery parties finding less stranded costs. In this context, it seems reasonable to minimize the risk that the Commission or other stranded cost decision-maker will order a stranded cost charge based upon materially incorrect and inaccurate assumptions. The rule of thumb should be: the less confidence one has in the results of the initial stranded cost calculation, the more essential that a true-up mechanism be implemented.

Also, it could be argued that a true-up mechanism designed to ensure a certain level of stranded cost recovery by a utility would minimize the risk of the utility in that respect, perhaps allowing a lower cost of capital to be associated with stranded cost amounts. In other words, the more certain the recovery of a set amount of stranded costs, the less risk is placed on the utility, and the required return can be accordingly reduced.

Notwithstanding the above argument, advocates of true-ups note that these mechanisms can be designed not to guarantee the utility a set amount of stranded cost recovery or a specific return on stranded assets, but rather only to correct major discrepancies between stranded cost estimates and actual amounts incurred.

2. Arguments Against True-ups

Those opposing the use of true-ups in stranded cost proceedings emphasize the following four arguments: (1) there should be no guarantee of stranded cost recovery, (2) lack of incentives to minimize stranded costs, (3) the importance of certainty in the electric market place, and (4) potential anti-competitive impacts.

As has been discussed, utilities under normal ratemaking are not guaranteed profits sufficient to allow a reasonable rate of return to be earned; they are instead given the opportunity to earn a reasonable rate of return. It has been commonly held that, if recovery is to be provided for stranded costs, the utilities should be given only an opportunity to recover these costs, not a guarantee of recovery. True-ups designed to make utilities whole over time for specific stranded cost estimates can be thought of as "guaranteeing" a certain level of recovery. This leads to the anomalous situation where a utility would be given more certainty in recovering the costs of above market assets than of its other assets.

If given guaranteed recovery of specific stranded cost amounts through use of true-ups, a utility is not likely to seriously attempt to reduce or mitigate its stranded costs. Only if a utility faces a certain amount of risk in ultimately recovering stranded costs will it have an incentive to reduce that risk by mitigating its stranded costs.

It has been argued that the financial community and potential electric competitors may value the certainty of knowing what the future stranded cost charges will be, compared to the perceived benefits of potential reduction (or the risk of future increases) in those charges due to use of true-ups.

Finally, there is a perceived danger that, under some circumstances, use of true-ups could allow anti-competitive behavior on the part of incumbent utilities. Specifically, these companies could conceivably reduce their rates to the level necessary to forestall competition within their service territories, and make up the difference between their former rate levels and the new "competitive" level through the vehicle of true-up calculation of stranded cost charges. Whether, and if so to what extent, this is a real threat or not depends upon how the true-up mechanism is structured.

3. Conclusions About True-ups

It is a significant benefit to the entire restructuring process if any stranded cost quantification can be done once and not have to be revisited, thereby eliminating the need for true-ups. However, it would be premature at this time to reject use of any specific methods to quantify stranded costs. Since we view use of true-ups as desirable for correcting possible inaccuracies and miscalculations if administrative or combination methods are used, the following are our recommendations on the use of true-ups to update stranded cost calculations.

While using true-ups only in the "mid-course" correction sense would eliminate most of the concerns regarding reconciliations expressed earlier, there is at least one variable that enters into stranded cost calculations that is so inherently unpredictable that use of true-ups as make-whole provisions must be strongly considered. Specifically, the market price of power is a value likely to be volatile and very difficult to predict to the degree that leaving past stranded cost recovery uncorrected for this item may lead to gross inequities in stranded cost collections compared to actual stranded costs.

Therefore, we recommend that use of periodic true-ups to correct substantial inaccuracies in administratively determined stranded cost amounts be strongly considered, with such true-ups to reflect, at a minimum, retroactive correction of market price estimates. There may be other variables for which retroactive correction would also be appropriate. However, reflection of past over- and under collections associated with any corrected variables should be factored into the new trued-up stranded cost rate for prospective collection from or reimbursement to customers only; there should be no refunds of past stranded cost overcollections by the utility or special assessments to customers to recoup past undercollections.

E. Estimates of Stranded Costs for Missouri Utilities

As is clear from the foregoing discussion, a wide variety of techniques can be employed to estimate potential stranded costs. And, in applying any particular methodology, a wide range of assumptions could be employed with respect to each individual parameter.

To illustrate the uncertainty in the estimation of stranded costs for utilities serving customers in Missouri, we have gathered information from recent estimates made by independent parties.[22] (It should be understood that these estimates are made as of a certain date and that an estimate made at a different date may produce a different result.)

The following table shows a wide range of estimates.

[22] In this context, independent means that the estimate was made by an entity other than the utility for whom stranded cost was being estimated.

Recent Estimates of Stranded Costs
($ Millions)

Line	Source	Publication Date	Empire District Electric Co.	Kansas City Power & Light Co.	St. Joseph Light & Power Co.	Union Electric Company	UtiliCorp United
1	Moody's Investors Service*	12/96	zero or negative	303	N/A	zero or negative	481
2	Resource Data International (RDI)*	4/97	(234)	520	(53)	1,121	(259)
	Kansas Retail Wheeling Task Force						
3	▸ McFadden/RDI**	4/97	3	534****	N/A	N/A	84
4	▸ NRRI***	9/97	N/A	(14) to 155	N/A	N/A	N/A

* Total all states
** Kansas operations only
*** Kansas operations and generation units only
**** Total company amount is approximately $1.2 billion
N/A = Not Available

Note:
A positive number means that the book value of generation assets is larger than the market value.

The estimates taken from Moody's and RDI (Lines 1 and 2) are comparable in the sense that they both address the totality of the operations of each utility. That is, they consider operations in all states for multi-state utilities.

As an example of the variation in estimates, Moody's estimates that Union Electric Company (now AmerenUE) would have no (or negative) stranded costs, while the RDI estimate is stranded costs of approximately $1.1 billion. Interestingly, the estimates for UtiliCorp are in the opposite direction. Moody's estimates stranded costs of $481 million, while RDI estimates stranded costs at negative $259 million.

Lines 3 and 4 present available information from the Kansas Retail Wheeling Task Force. The McFadden/RDI study is shown on Line 3, and the NRRI evaluation is shown on Line 4. The data here are not comparable to the data shown on Lines 1 and 2 because the Retail Wheeling Task Force focused only on Kansas operations. Further, the NRRI evaluation looked only at generating plants located in the state of Kansas. With respect to Kansas City Power & Light Company, it did observe that including all KCP&L generating facilities would make the estimated stranded costs essentially zero. It is also interesting to note that the McFadden/RDI estimate for KCP&L's Kansas operations is approximately the same as the separately reported RDI estimate for stranded costs of KCP&L's operations in both Missouri and Kansas.

This review emphasizes the extreme sensitivity of stranded cost calculations to the selected methodology, the time frame analyzed and the specific assumptions with respect to the key parameters.

F. Overall Conclusion

To reiterate, it is our belief that avoidance of true-ups would be beneficial to any electric restructuring process. However, we also recognize that use of pure market methods will not be feasible in every foreseeable circumstance. Each market method has its unique risks and advantages. Because the best market mechanisms require structural separation and asset divestiture, these methods are not always easily applied. While divestiture is also a consideration for resolving market power concerns, we do not believe asset divestiture is justified solely on stranded cost quantification considerations. There are also methods of quantifying stranded costs that do not require divestiture, but do use market determined price data, though these mechanisms have various drawbacks and entail certain risks. In our report, we have referred to these as "combination" methods.

We recommend that the Legislature and/or Commission, for purposes of determining stranded cost amounts, operate under a policy that methods of quantifying stranded costs should utilize available market information to the extent possible. "Combination" methods should be seriously considered. If administrative methods are to be used, market information should be used to support the results of the analysis as much as possible. However, strong consideration should be given to subjecting any stranded cost amounts set through administrative means to periodic true-ups or reconciliations in a manner that does not impair the utility's incentive to mitigate stranded costs amounts or adversely affect the development of a competitive market for the supply of generation at the retail level.

CHAPTER IV

Timing of Recovery

This chapter addresses the issue of the time frame during which allowable stranded costs (if any) would be recovered from retail electric consumers in conjunction with a program for retail access. For purposes of illustration only, it is assumed that some amount of stranded cost exists and is to be collected from retail consumers. The illustration is neutral with respect to the proportion of identified stranded cost to be recovered from consumers (i.e., the illustrative examples do not depend upon the percentage of recovery).

A second scenario is presented to address the circumstance where stranded cost is negative.

A. Positive Stranded Costs

Figure IV-1 shows the typical revenue requirement trajectory for generating resources. The pattern is a reduction over time as generating assets depreciate. (The particular slope of the line also depends upon other factors, including the rate of change in O&M expenses.) The specific slope of the line is not critical to the illustration. The general point is that over time the revenue requirement associated with a particular generating facility is expected to decrease. At the same time, the market price of power (i.e., the revenue that could be produced by competitively selling output from the generator) is expected to increase.[23]

Two different examples for timing of recovery are addressed. The first involves a two-step recovery process and the second illustration involves a three-step recovery process.

Figure IV-2 assumes that the recovery process starts with a rate freeze for a certain number of years. The rate freeze is designed to allow the utility to charge rates in excess of its then current revenue requirement in order to collect or pay down a portion of the allowable estimated stranded costs. By charging rates in excess of the then current revenue requirement for the existing generating facilities, the utility receives funds that otherwise would not have been collected (because rates presumably could have been reduced) and applies them to reduce existing generating asset balances.

[23] For purposes of illustrating how stranded cost recovery works, it is necessary to focus on the existing array of generating units. It is recognized that over time a utility will experience growth and will undoubtedly add new facilities. Stranded cost does not address the cost of new facilities, however. It addresses the relationship between the traditional revenue requirement for existing facilities and their value in the market. If these new facilities were included, the slope of the revenue requirement line for the combination of existing plus new facilities would be much more gradual than in the illustration.

When open access is granted, the rates would decrease and a level of Stranded Cost Charge (SCC) recovery would be set in place. The level of the charge, and its duration, would have to be determined as a function of the estimated remaining amount of stranded cost, the minimum reduction in rates that the Commission wanted consumers to enjoy, and the particular sharing (if any) of stranded cost recovery between consumers and stockholders. An initial estimate of stranded costs would have to be made prior to the date of implementing the selected recovery process. This amount could be fixed, or there could be mechanisms in place for adjusting the frozen rate and/or the SCC if new and better information became available.[24]

Figure IV-3 shows, after the open access date, the combination of the SCC charge paid to the utility and the market price of power paid by the customer to its chosen supplier.

Figure IV-4 shows a second example with a three-step process for stranded cost recovery. The first stage is the same as in the first example, but the rate freeze is in place for a shorter period of time. Again, an estimate must be made up-front of the expected level of stranded costs; however subsequent market tests and adjustments can be made as with the prior illustration. The second step is a reduced rate reflecting a lower level of recovery for an interim period. The final step is a lower value of SCC, as compared to the second step, which allows for recovery of the balance of the allowable stranded costs. Under this example, the final level of SCC is probably higher than in the second step of the first example, and probably extends for a longer period of time; all other things equal.

Figure IV-5 shows the combination of the SCC charges and the market price for power paid by the customer during the period that this SCC is being applied.

It should be noted that in the first recovery example there is more time to prepare for open access, and the utility collects a larger proportion of the allowed amount in the early years. However, consumers do not have the opportunity to purchase competitively as early, and they pay higher rates at the beginning of the period. The second example extends the period over which stranded cost recovery occurs, but provides consumers the opportunity to achieve savings earlier in the process.

[24] See the discussion in Chapter III with respect to various methods for estimating stranded costs.

B. Negative Stranded Costs

For purposes of illustrating negative stranded costs, the market price line is the same as in the illustration of positive stranded costs, but the revenue requirement line in this scenario begins at a lower value to recognize a lower embedded cost for the utility whose existing revenue requirement is closer to the market price of power (see Figure IV-6). Figure IV-7 shows the SCC, which is a negative value to reflect credits to consumers for the amortization of negative stranded costs. Figure IV-8 shows the combination of the negative SCC and the market price of power which the customer would be paying.