POLICY CHOICES FOR ELECTRIC-UTILITY STRANDED COSTS

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1. INTRODUCTION

The U.S. electricity industry is in the midst of major changes in its structure, operations, and regulation. These changes are driven by many forces, including federal legislation (especially the Energy Policy Act of 1992) and regulation, state legislation and regulation, improving technologies (especially for combustion turbines), low natural-gas prices, and a widespread belief that competitive markets can better meet customer needs than can regulated markets.

The electricity industry today is dominated by vertically integrated utilities,[*] each of which enjoys a retail-monopoly franchise granted by the state. In return for this monopoly franchise, utility rates and services are regulated by state public utility commissions (PUCs). (Publicly owned utilities, such as municipal utilities and rural cooperatives, are usually self-regulating.)

The electricity industry of tomorrow may involve separate companies that generate, control, transmit, and distribute electricity, and that offer retail electricity services. The industry may be competitive at both the wholesale and retail levels and, as a consequence, generation services may be free of much of today's state regulation. The transition from one type of structure to another will, for some utilities, expose costs that cannot be sustained in competitive markets.

Stranded costs (SCs) are the potential monetary losses (or, in some cases, gains) that electric-utility shareholders or other parties might experience because of structural changes in the electricity industry.[#] SCs typically do not include losses or gains associated with the normal business risks that utilities face under traditional regulation, such as changes in load growth and introduction of new technologies. SCs are the differences between the market and book values of the utility's generation-related assets, both physical and regulatory assets. A utility's entire portfolio of assets and obligations must be considered to estimate *net* SCs.

In essence, the retail monopoly franchise that investor-owned utilities enjoy today permits them, with approval from their state regulatory commission, to charge customers for the prudently incurred costs of producing electricity even if such costs exceed what the market would allow. In a competitive electricity market, the frequent interaction of buyers and sellers, rather than regulators, will set prices. If these prices are such that the utility is unlikely to

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[*]Vertically integrated utilities build and operate power plants, transmission systems, distribution systems, and customer-service operations all within one company.

[#]These potential losses are sometimes called transition costs, potentially stranded costs, stranded investment, or excess costs over market.

recover these embedded (book) costs,* then stranded costs will arise. Although each state may define SCs to meet its unique conditions, the definitions generally limit SC recovery to costs that are "legitimate, prudent, and verifiable" and directly related to the state's action in permitting competition for retail electricity consumers.

The costs discussed here—both positive and negative—already exist and are, in general, reflected in today's retail electricity rates. Increasing competition exposes these costs to view, but generally does not create new costs.# Legislators, regulators, and others need to address the allocation of these costs up front and establish clear rules to determine how they will be measured and shared among different groups (e.g., utility shareholders, retail customers in different classes, wholesale suppliers, and taxpayers). Government failure to render clear policy decisions on the magnitude and allocation of these costs will likely cause serious problems, including extensive litigation and delays in the implementation of competitive markets. Finally, once the transition from today's vertically integrated, regulated, monopoly industry to a more competitive industry is complete, this issue will disappear if its resolution is considered fair by all market participants. However, the large dollar amounts at stake ensure that stranded costs will be a critical issue for the next few years.

2. TYPES OF STRANDED COSTS

Stranded costs generally fall into three categories:

- Assets, primarily in expensive power plants and excess generating capacity. For example, some utilities own nuclear plants that cost much more to build than do today's power plants. In a competitive electricity market, the price received for the electrical output from these expensive plants would not be enough to repay the remaining (undepreciated) capital costs of the plants.

- Liabilities, primarily in expensive power-purchase contracts and fuel-supply contracts, as well as contingent liabilities such as nuclear-plant decommissioning.

- Regulatory assets, whose value is based on regulatory decisions rather than on market forces. They include deferred expenses and costs that regulators allow utilities to place on their balance sheets, such as those associated with public-purpose programs. For

[*] Embedded cost is the total historic or presently committed cost of owning (construction), operating, and maintaining the utility system to provide electrical service to customers.

[#] Other costs associated with the transition to competition could include consumer education, early retirement and retraining for utility personnel, and development of electronic information and trading systems. Although some states consider these costs as SCs, they are not addressed in this paper.

example, a regulatory commission might agree to defer some of the costs of an expensive new power plant to avoid "rate shock." The commission might allow the utility to add these costs to rates gradually over several years. In essence, this agreement is a promise from the state regulator to the utility that ultimately, although not today, it will recover all its costs. If the utility's customers can choose alternate suppliers, however, the regulator may have difficulty keeping this promise to the utility.

Stranded costs can have both positive and negative values, although for many utilities the positive costs exceed the negative ones. It is important to calculate *net* SCs, rather than *gross* SCs, for a particular utility to avoid overestimating the actual SC amount. *Gross* SCs would consider only those assets and obligations with market values less than book values and ignore those assets and obligations with market values above book values.

3. STRANDED-COST MAGNITUDES

The amounts of money at stake are potentially large. Estimates of stranded costs vary widely, with many falling in the range of $100 billion to $200 billion for the United States as a whole. Compare that range with the total shareholder equity in U.S. utilities of about $190 billion. Moody's Investors Service, as an example, analyzed data for 116 utilities, representing more than 80% of the assets of all U.S. investor-owned electric utilities. Moody's estimated that stranded costs could range from $50 billion to $300 billion, with the most likely value being $136 billion, equivalent to almost 90% of shareholder equity for these utilities.

Not only is a great deal of money at stake, but that money is distributed unevenly across utilities, states, and regions. Certain low-cost regions of the country (e.g., the Pacific Northwest) have little exposure to stranded costs relative to other regions (e.g., California and the Northeast), which face substantial exposure to such costs.

In late 1996, Resource Data International estimated a nationwide SC of $184 billion. Of this total, $134 billion is accounted for by investor-owned utilities, $29 billion by municipal utilities, and $20 billion by cooperatives. Utility-owned generating units account for the largest share of the $184 billion, $65 billion. RDI calculates the nationwide SC for nuclear units at almost $79 billion, offset by a negative SC for fossil and hydro units of $15 billion. Regulatory assets account for $45 billion of SCs, power-purchase contracts with nonutility generators for $38 billion, power-purchase contracts with other utilities for $49 billion, and power-sales contracts for a negative $11 billion.* California, New York, and Texas together account for more than 40% of U.S. SCs, according to this analysis.

RDI also identified several utilities with below-market costs, leading to a total negative SC of $54 billion. In general, these utilities had little exposure to nuclear plants and had many other generators with embedded costs below market prices. These utilities also had few regulatory assets and had large potential gains from their power-sale contracts.

Because of the large dollar amounts at stake, controversies often arise over the magnitude of SCs that a particular utility faces. Even when the parties are required to use the same, very simple analytical approach, large differences in SC estimates can and do occur (Exhibit 1).

A recent report from the Texas PUC shows how sensitive SC estimates are to different assumptions (Fig. 1). For this utility, high electricity prices lead to a negative SC, whereas low prices lead to a large positive SC. The PUC benchmarking, which adjusts utility estimates of administrative and general costs, general plant costs, and capital-addition costs, further reduces the SC estimates.

4. REGULATORY AND LEGISLATIVE ISSUES

State legislatures, regulatory commissions, utilities, and their customers face six key questions concerning stranded costs:

- How should the legislature and PUC define stranded costs? For example, how can they limit such costs to those that are a direct consequence of the decision to permit retail competition and exclude those associated with technological advances and other forms of competition? What is an appropriate return on investment for recovery of SCs?

- How should the PUC determine utility-specific SC magnitudes? In particular should it use market methods (e.g., auctions of generating assets) or administrative methods (e.g., analytical tools and associated data requirements)?

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*The $49 billion cost and $11 billion gain do not offset each other. The $49 billion represents above-market purchases for utilities with net positive SCs. Other utilities have above-market purchase contracts with utilities, but those costs are offset by below-market generation and are not included in the $49 billion total. However, aggregating power-sale and -purchase contracts across all utilities would yield identical dollar amounts.

Exhibit 1. Differing Estimates of Stranded Costs

In a wholesale SC case involving El Paso Electric and the City of Las Cruces, New Mexico, the utility's estimate of SCs was seven times higher than the city's and more than four times higher than that of the Federal Energy Regulatory Commission (FERC) Trial Staff (Table E1). The large differences among these estimates is surprising, given the simplicity of FERC's top-down approach to calculating SCs. FERC's revenues-lost formula includes only three factors:

- Revenue Stream Estimate, the average annual revenues from the departing generation customer over the three years prior to the customer's departure, less the average transmission-related revenues that the host utility would have recovered from the departing generation customer over the same three years under its new wholesale transmission tariff.

- Competitive Market Value Estimate, determined in one of two ways: (1) the utility's estimate of the average annual revenues over the reasonable expectation period (L) that it can receive by selling the released capacity and associated energy, based on a market analysis performed by the utility; or (2) the average annual cost to the customer of replacement capacity and associated energy, based on the customer's contractual commitment with its new supplier(s).

- Length of Obligation (reasonable expectation period), the period of time the utility could have reasonably expected to continue to serve the departing customer.

Table E1. Alternative estimates of the amount of stranded costs associated with the departure of the City of Las Cruces from the El Paso Electric system

Factor[a]	El Paso Electric	FERC Trial Staff	City of Las Cruces
Revenue stream estimate ($/MWh)	76.0	64.5	62.4
Competitive market value estimate ($/MWh)	34.2 (1998) to 46.8 (2007)	42.3 (1998) to 45.0 (2007)	43.3 (1998) to 54.4 (2007)
Length of obligation (years)	20	5	0–4
Stranded cost obligation (million $)	137	29	20

[a]FERC's revenues lost method is SCO = (RSE - CMVE) x L.

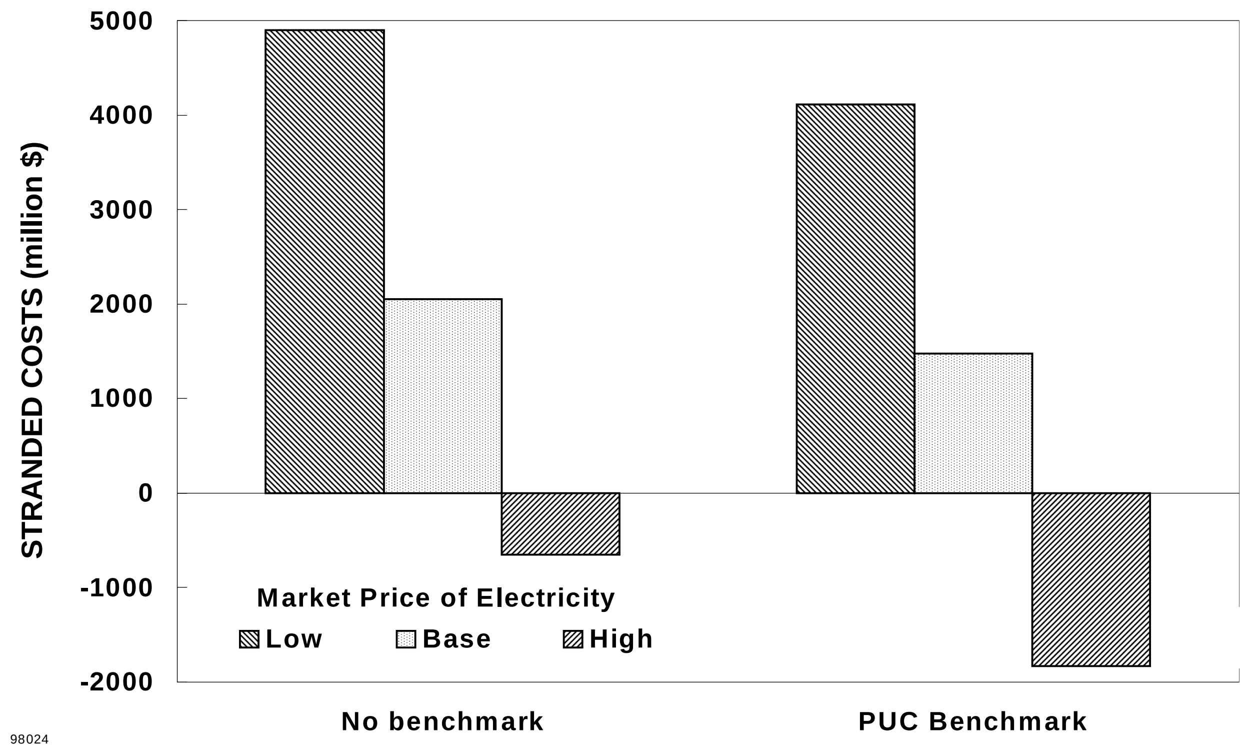

Fig. 1. **Stranded-cost estimates for Houston Lighting & Power made by the Texas PUC assuming retail competition begins in 2001.**

- How much money is at stake for each utility and how do these amounts vary with changes in key assumptions?

- How can the utilities, PUC, legislature, and others mitigate or, more accurately, offset these costs?

- How should the remaining costs be allocated among utility shareholders, different classes of retail customers, taxpayers, and perhaps others?

- What cost-recovery and trueup mechanisms could be used to equitably share risks between the utility and its customers and to promote competitive generation markets?

The remainder of this paper addresses each of these issues.

5. MARKET VALUATION ESTIMATION METHODS

Utilities and regulators can use a variety of approaches to calculate stranded costs. All approaches compare the regulated-market (i.e., book) values of utility assets and liabilities with their competitive-market values. Alternative approaches can be categorized along three dimensions. The first dimension is the use of administrative vs market procedures to value the assets in question. Administrative approaches use forecasting, modeling, or other analytical techniques to estimate stranded costs. Market valuation relies on the purchase price of particular assets to determine their market values. The second dimension concerns when the valuation is done, either before or after restructuring of the electricity industry is completed. The third dimension concerns the level of detail involved in the valuation, what is often called top-down vs bottom-up valuation.

As of May 1998, several utilities have conducted auctions resulting in the sale of generating units at prices well above their book values (Table 1). According to the Edison Electric Institute, 27 utilities have sold or announced the sale of more than 53,000 MW of capacity. The prices obtained to date suggest that the market values these units more highly than the accounting numbers imply; that is, the market prices were above book values. Thus, divestiture of generation may be a powerful way to reduce stranded costs. Indeed, several states (e.g., California and Massachusetts) conditioned SC recovery on the utilities' willingness to sell substantial portions of their generating assets.

Table 1. Relationship between sale price (market value) and book value for 22,000 MW of generating capacity sold in 1997 and early 1998

Selling utility	Capacity sold (MW)	Ratio of sale price to book value
Boston Edison	1,983	1.2
Central Maine Power	1,185	3.5
Commonwealth Edison	1,598	1.0
Commonwealth Energy	984	5.8
EUA	244	1.9
New England Electric	3,960	1.5
Pacific Gas & Electric	2,745	1.3
Southern California Edison	9,562	1.9
Total	22,261	1.7

Market valuation offers several benefits relative to administrative determinations of SC amounts. First, the use of markets to determine the values of what might be stranded assets and liabilities provides an unambiguous determination of their value; this market determination means that the state regulatory commission need not conduct the equivalent of lengthy and contentious rate cases, what one utility lawyer called "the mother of all rate cases."[*] Second, the price obtained in an auction or through careful negotiation will reflect the highest (not the average) value of the assets; that is, the prices at which these assets and long-term contracts are sold reflect the highest bids offered. Third, sale of generating units and long-term power-purchase contracts can reduce market concentration, which in turn reduces potential market-power abuses. Finally, once the assets and liabilities are sold, the amount of SCs remaining may be smaller (and perhaps zero or even negative); thus the transition period can be shorter than when an administrative-determination approach is used. The sale of the fossil and hydro generating units owned by the New England Electric System cut its SCs in half.

On the other hand, a poorly designed and badly timed auction could produce bids well below the true market values for the assets and contracts being sold. In such a case, utility customers would be asked to pay stranded costs much higher than they need to. Some analysts worry that the simultaneous sale of too many megawatts of generating capacity could lead to a "fire sale" with very low prices. The sale of generating units before the structure and operation of competitive generation markets are established could yield sale prices that are not reflective of their long-term market value. However, the experience to date suggests that these concerns may not be a problem.

Three articles in the December 1997 issue of *The Electricity Journal* discuss the use of auctions to value generating units. They take different views concerning the appropriate design of such auctions and the importance of auction design on sale prices. The auction format used by utilities to date calls for only one round of sealed bids. The approach used by the U.S. Federal Communications Commission to auction parts of the electromagnetic spectrum used multiple rounds of bidding. Multiple rounds might yield higher prices because bidders can adjust their offers from round to round to assemble the portfolios of resources in which they are most interested.

As an alternative to a sale of assets, utilities could spin off generating assets to a separate division of the company or to a new company. The value of that company, as reflected by its stock price, could be used to determine the market value of the generating assets. Determining the appropriate time(s) to observe the stock price may be difficult and contentious, however. The stock price of a spin-off will reflect not only investors' perceptions of asset value but also the value of the new company's management and staff, among other characteristics. Once customers, through a stranded-cost charge, have paid shareholders for the remaining book value of these assets, shareholders have no further claim on customers for these assets.

[*]Utilities have much more information about their generating resources and associated costs and uses than do the other parties in such cases. This information asymmetry makes it possible for the utilities to manipulate these data in ways that inflate SC estimates. The PUC, its trial staff, consumer groups, and other parties to these cases may have difficulty detecting such manipulations.

Another alternative to full divestiture (e.g., where the state determines that divestiture is not required to mitigate market power) would involve creation of a new generating-company subsidiary. The utility would place all its generating assets (except, perhaps, its nuclear assets) in this subsidiary and would then sell a small share (e.g., 20%) of this entity in the open market through an initial public offering. The average price of these publicly traded shares over some predetermined period (e.g., 6 to 12 months) would be used to calculate the market value of this subsidiary's assets relative to their book value. The utility could later decide whether to sell the rest of the subsidiary or to retain its control.[*]

When considering the specific market-valuation approach to use, the potential tax implications should be assessed. A sale of assets, such as the divestiture of utility generating plants for cash, will be treated as a taxable event for federal and state income-tax purposes. A spin-off transaction will not be considered a taxable event if the transaction conforms with tax laws dealing with spin-offs. The potential tax consequences of different market-valuation approaches suggest a need to consult with the Internal Revenue Service prior to implementing a specific process. Asset sales may also raise complications with mortgage bonds, many of which are backed by specific assets.

Because different market-valuation approaches have different tax effects, decision makers should look beyond market value in deciding between auctions and spin-offs. An asset would have to sell well above the value of a spin-off to yield the same after-tax proceeds. In addition, the transaction costs associated with these different approaches must be considered, particularly if ratepayers are funding some portion of these activities. Further, unless the sale or spin-off is straightforward (e.g., an asset sold at auction with many bidders), determining the market value or the net proceeds from the transaction may be complicated. For example, a sale or spin-off may include the purchase of operations and maintenance (O&M) contracts, plant output, or supplemental services. Regulators must then separate the payment for the asset itself from these other purchases.

6. ADMINISTRATIVE ESTIMATION METHODS

Administrative-valuation approaches use analytical techniques similar to those used in traditional rate cases to estimate the market value of utility assets and obligations. Bottom-up options compare the fixed costs of individual assets and obligations with the operating income (revenues minus operating expenses) produced from their electricity sales. Stranded costs arise when a plant's operating income does not cover its fixed costs. In contrast, a plant

[*]The Ford Motor Company and several other companies have used this approach to assess wholly-owned subsidiaries. Selling less than a majority interest may yield a depressed sale price because the minority owner would be subject to the majority owner's management decisions. Regulators may want to adjust the sale price upward to reflect this control penalty.

with operating income in excess of its fixed costs can help offset the unrecovered fixed costs of another plant. Thus, a utility's entire portfolio of assets and obligations must be considered to estimate net SCs.

A bottom-up administrative approach requires calculation of the unit-by-unit performance of each of a utility's power plants in a hypothesized competitive generation market. Some early estimates of stranded costs were too high because they were based on an analysis of only those generating units with book values above market values, leading to an estimate of *gross* costs. An accurate assessment of such costs must include all assets, those with book values below as well as above market values, to derive an estimate of *net* stranded costs.

Calculating the return provided by each generating unit involves detailed production simulations for both the utility in question and the surrounding utilities and independent power producers. Such calculations require thousands of assumptions concerning customer loads, transmission-system characteristics, and the operation and costs of individual generating units. As shown in Table 2, there are many ways to manipulate these assumptions to obtain estimates of bulk-power market prices that are too low (leading to an overestimate of actual SCs) or too high (leading to an underestimate of SCs).

The top-down approach, rather than using the individual asset or liability as the unit of observation, treats the utility as the unit of observation. In a top-down administrative approach, the utility's average embedded cost of electricity production is compared with an average assumed market price. This approach is much simpler than the bottom-up approach, primarily because it requires only a few assumptions and elementary calculations. However, it is also much less detailed and, therefore, provides few insights into the specific assets, liabilities, and costs that account for a utility's stranded-cost situation (Fig. 2). This approach is also likely to overestimate SC amounts because it cannot identify individual generating units that should be shut down (i.e., because their revenues are not enough to cover at least variable plus fixed O&M costs). FERC's revenues-lost approach, included in its April 1996 Order 888, is a top-down method (see Exhibit 1).

Regulators might prefer top-down methods because of their administrative simplicity and reliance on readily available data and computer models. Such methods are well suited for developing initial estimates of the magnitude of the stranded-cost problem for a particular utility or state. However, in regulatory determinations of the actual dollar amounts to be recovered, commissions might prefer the greater detail of bottom-up methods. This detail is especially important if commissions decide to authorize recovery *of* utility-shareholder investment in certain assets but not necessarily recovery *on* these investments (i.e., return on equity), or if regulators want to allow utilities to recover different fractions of SCs for different types of assets and liabilities.

Table 2. Factors that affect estimates of future market prices for electricity

Factor	Treatment that raises the SC estimate[a]
Generation-provided ancillary services, such as regulation, load following, and spinning reserve	Ignore the revenues associated with the sale of these services
Capital costs of new generating units, generally combustion turbines and combined-cycle units	Ignore interest payments during construction, state income taxes, property taxes, and the higher equity:debt ratio and higher returns on bonds and equity associated with competitive generation-only companies, all of which underestimate capital costs
Performance of new generating units	Assume low heat rates and high availability factors, inconsistent with low values for capital cost
Generating-unit heat rates	Use incremental heat rates, which are lower than average heat rates.
Fuel costs	Use only the variable cost of fuels, ignore the fixed costs of long-term fuel-supply contracts; use low estimates of future natural-gas and coal prices
Startup and no-load costs	Ignore these costs
Emissions-compliance costs	Ignore the costs of SO_2 allowances and the costs of NO_x compliance
Pumped-storage hydro facilities	Ignore the costs and inefficiencies of pumping and consider only the generation output from such facilities
Load growth	Ignore the possibility of higher load growth stimulated by competition-induced lower electricity prices
Transmission costs, losses, and congestion	Ignore these factors

[a]Alternative assumptions and treatments could have the opposite effect of lowering the SC estimate.

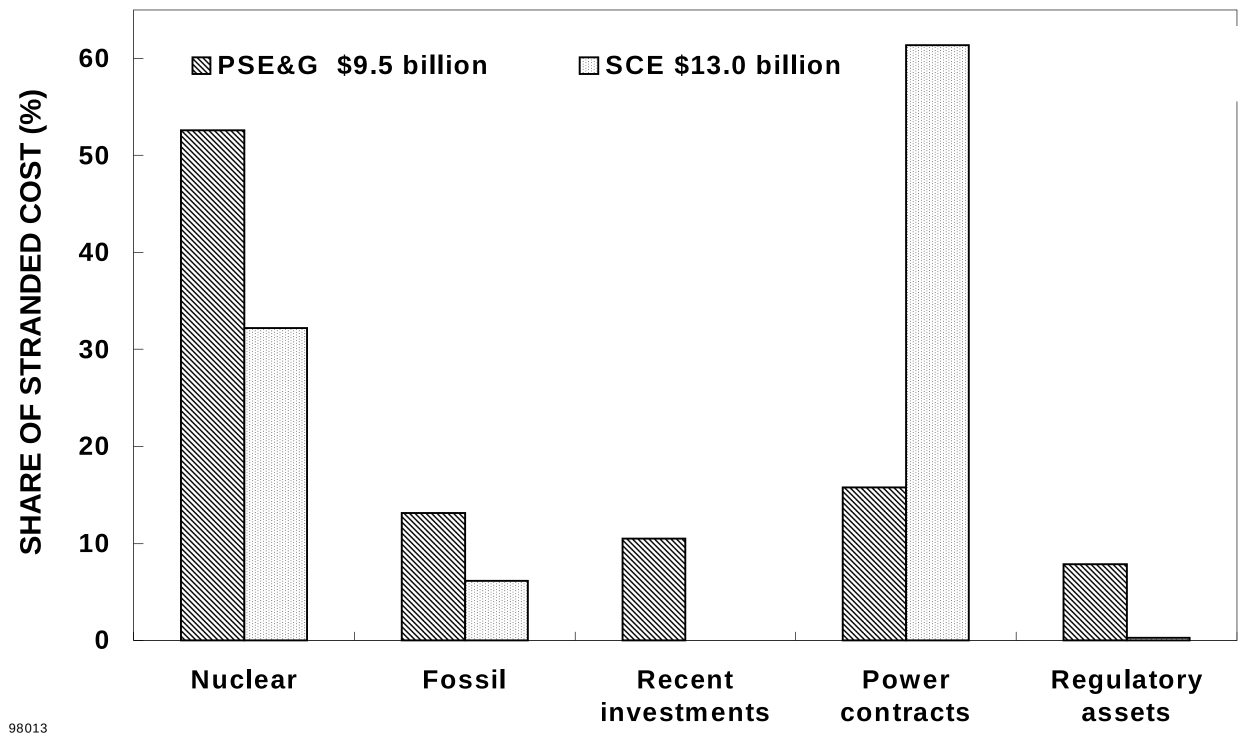

Fig. 2. **Although these utilities have SC amounts that are comparable, their cost allocations are quite different. The costs for Public Service Electric & Gas are dominated by expensive nuclear plants. The costs for Southern California Edison are dominated by contracts with qualifying facilities.**

Regardless of the method used to estimate the amount of stranded costs, one must make certain assumptions. Although many factors affect the calculation of SCs, only a few factors make a big difference. The most important factors affecting SC magnitudes include the future market price of electricity, when retail access begins, extent of retail access, amount of utility regulatory assets, and utility fixed production costs. Factors likely to have little effect on estimates of SC amounts include public-policy program costs, inflation rate, customer load factors, and transmission and distribution system loss factors.

Of the critical factors that affect stranded costs, some can be influenced by the utility and some by the PUC, and some are essentially beyond the control of either party. As examples, the PUC can affect the start date and extent of competition, although market forces may overwhelm regulation where large regional price disparities exist; and utilities can seek to cut their fixed and variable production costs. But wholesale prices—probably the most important factor—are largely independent of utility or PUC actions.

Because so many assumptions are required to develop estimates of the dollar amounts at stake, regulatory commissions may want to apply periodic adjustments to their initial estimates. Such trueups (discussed below in Section 9) would reduce the risk that any group would pay too much or enjoy windfall profits. On the other hand, the regulatory proceedings associated with such trueups could be complicated, time consuming, and litigious. And, unless properly designed, such mechanisms could reduce a utility's incentive to perform efficiently.

7. OTHER FACTORS THAT AFFECT SC ESTIMATES

RELEVANT TIME PERIODS

Analysis of SC recovery involves two distinct time periods: (1) the book lives of the relevant assets (utility-owned generating units) and liabilities (long-term fuel-supply and purchase-power contracts) and (2) the SC-recovery period. The first period involves analysis of year-to-year SCs should continue until the longest-lived asset is retired or the longest-lived contract expires. In general, the utility's embedded cost of generation will decline over time. On the other hand, the market price of power will likely increase from the current short-run marginal cost (based on today's excess capacity) to the long-run cost of new generation (probably a gas-fired combined-cycle unit). Because these embedded-cost and market-price trends move in opposite directions, SCs may become negative at some point. Any calculation of the net present value of SCs should account for both the short-term positive costs and the long-term negative costs to provide an accurate estimate of the net stranded cost.

Figure 3 shows an estimate of the annual losses that Kansas Power & Light might face between 1996 and 2005 assuming that retail competition began in 1996. These costs are negative for all years after 1999, which means that the utility is expected to earn additional profits in competitive (vs regulated) markets from its generating assets each year from 2000 through 2005. If the analysis of SCs considers only the 1996–2000 period, the estimated SC would be $139 million. However, if the analysis considers all ten years from 1996 through 2005, the SC would be only $1 million.

The SC-recovery period, the second time period, is a policy choice, not an analytic determination. A short recovery period hastens the time when the monthly transition charge is eliminated and all generation suppliers operate on a similar basis. On the other hand, the shorter the recovery period, the greater the transition charge will be. Five years appears to be a typical cost-recovery period; California chose a four-year recovery period.

DISCOUNT RATES

Discount rates play an important role in estimating the amount of SCs a utility faces and in determining how much money the utility is allowed to recover during the PUC-specified transition period. Discount rates are used in three analyses that affect SC amounts and recovery.

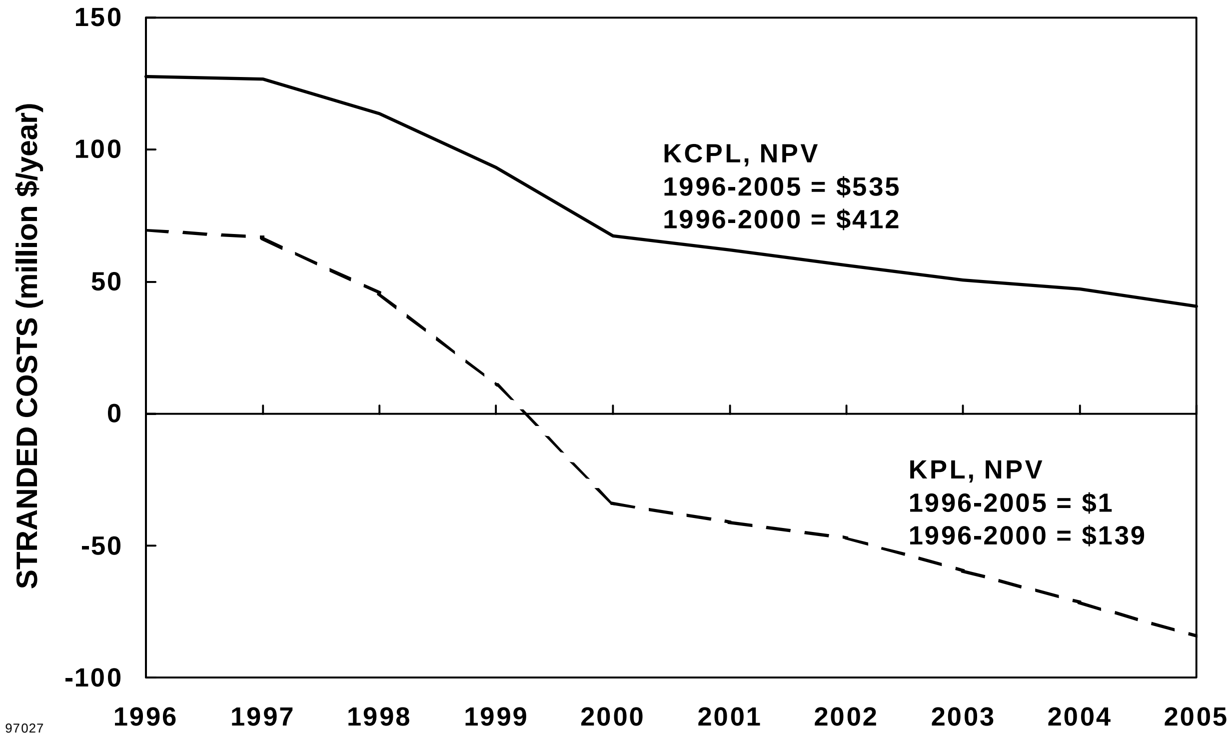

Fig. 3. **Estimated stranded costs for Kansas Power & Light and Kansas City Power & Light. If the analysis considered only the 1996–2000 period, the estimated SC would be $139 million instead of the $1 million associated with the full 10-year period.**

First, discount rates are used in calculating the annual losses that a utility might experience when its portfolio of generating resources is exposed to competitive forces. The utility's SCs are capped by its unavoidable fixed costs, which may include depreciation, property taxes, interest payments on long-term bonds, state and federal income taxes, and return on equity. In general, utilities calculate these annual losses using the capital structure, bond interest rate, and return on equity (ROE) approved in the most recent rate case. Thus, these calculations assume that the utility will recover its authorized ROE.

Second, this stream of annual losses is converted into a lump sum, representing the net present value of these annual dollar amounts as of the start date of retail competition. Conversion of annual payments to a single value requires a user-specified discount rate. To be internally consistent, the net present value amount should be calculated using the same ROE used in the first step. The ROE (shareholder perspective) is used in step 2, rather than the weighted average cost of capital (reflecting both bond- and shareholder perspectives), because shareholders alone bear any gains or losses associated with the transition from regulated to competitive generation markets.

Third, the state legislature or PUC decides on the length of the recovery period (e.g., five years). In addition, the PUC may decide that the utility's shareholders face little risk associated with recovery of these SCs, both because of the PUC-approved monthly transition charge and the much shorter recovery period (e.g., five years rather than the 20 to 30 years associated with the remaining book lives of the utility's generating assets). The PUC might elect to authorize a lower ROE on the SC payments, perhaps set at the utility's long-term bond rate as the Pennsylvania PUC did in a 1997 case involving PECO Energy. Similarly, the California PUC set the imputed return on equity for SC recovery of generating assets at a level 10% below the long-term cost of debt. A recent settlement involving Virginia Power calls for the utility to use "excess" earnings to reduce its SCs.

Consider the situation shown in Fig. 4. This example assumes that retail competition begins in the year 2000, at which time the utility's generating assets have a remaining book life of 19 years (through 2018) and a book value of $476 million. The utility's fixed-cost revenue requirements decline from $120 million in 2000 to $36 million in 2018.* On the other hand, the revenues collected by these generating units increase with time, from $62 million in 2000 to $97 million in 2018 because of increasing market prices and inflation. The net effect is a decline in losses, from $58 million in 2000 to zero in 2008 to −$60 million (a profit) in 2018. At the utility's authorized ROE of 12%, the net present value of these losses is $115 million, which the PUC accepts as the best estimate of the utility's SC exposure.

The annual payments to which the utility is entitled depend on the PUC's decisions concerning the transition period and the allowed ROE (top half of Table 3). The longer the recovery period, the smaller the annual payments that appear as SC charges on customer bills. And the lower the approved ROE, the lower the annual payments. With a 7-year transition period, a 7% return reduces costs to customers by 15%.

This example assumes that the ROE authorized in the utility's last rate case is valid today. Many utilities have not had rate cases for several years, during which time interest rates have declined substantially. For example, the average rate on utility bonds declined by two percentage points between 1990 and 1997, from 9.6% to 7.6%. A utility's ROE, while higher than the interest rate it pays on bonds, should track closely these interest rates. Thus, PUCs might establish SC-recovery amounts on the basis of an ROE lower than that approved in the last rate case to reflect today's much lower inflation and interest rates.

*The annual revenue requirements are calculated on the basis of a 50:50 debt-equity ratio, a long-term bond interest rate of 8%, and an ROE of 12%, yielding an overall cost of capital of 10%.

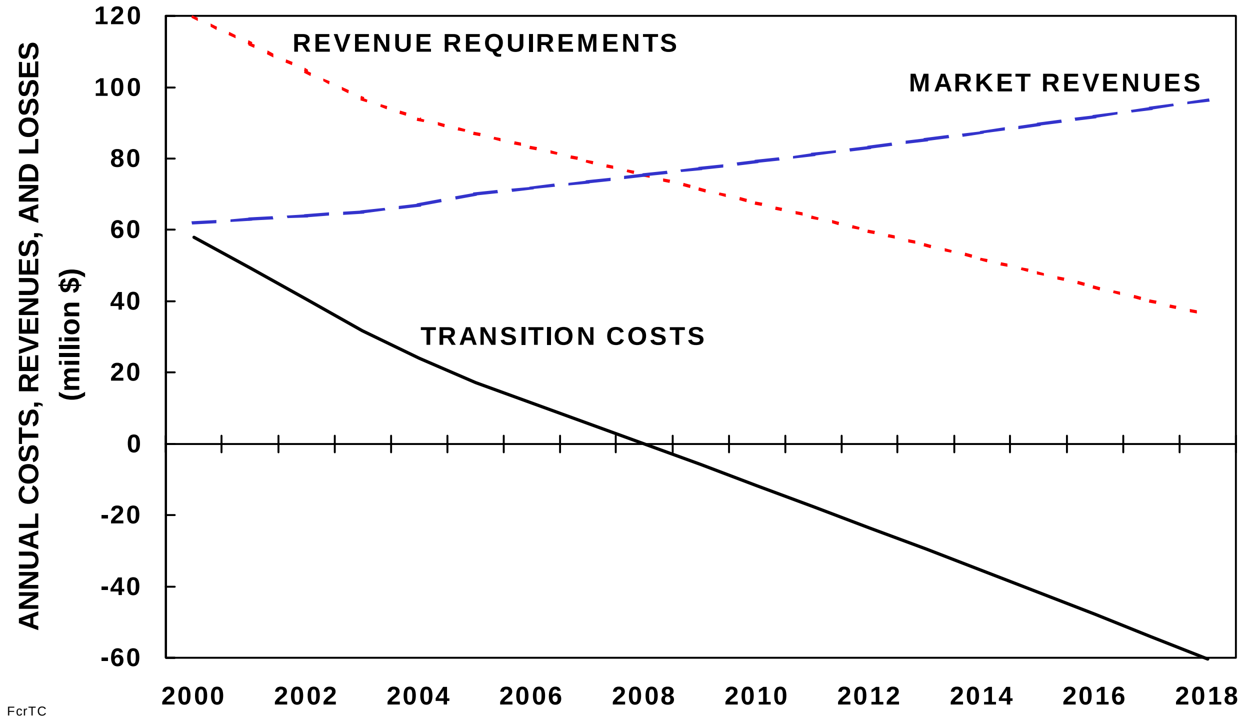

Fig. 4. Annual fixed-cost revenue requirements, market revenues, and stranded costs for a hypothetical utility.

Assume that the PUC decides, based on a 2-percentage-point decline in inflation rate, to lower the utility's long-term bond interest rate from 8 to 7% and to lower the utility's allowed ROE from 12 to 10%. These reductions lower the utility's revenue requirements from year to year. They have a large effect on stranded costs because the market revenues do not change in response to changes in the utility's cost of capital. For example, the revenue requirement is cut 8% in the year 2000, while the stranded cost declines by 17%. On a net present value basis, the utility's stranded costs are cut in half, from $115 million at an ROE of 12% to $57 million at an ROE of 10%.

The bottom half of Table 3 shows the annual SC recovery associated with the lower bond interest rate and lower ROE. For all combinations of allowed interest rate and years of recovery, the payments are roughly half of what they were with the original interest rate and ROE.

Table 3. Annual SC recovery as functions of utility cost of capital, allowed return on equity, and SC-recovery period

	Transition period (years)	Annual payments (million $) for an allowed return on equity equal to the actual value or 7%	
		Allowed return on equity	
Utility return on equity = 12% (SC = $115 million)		12%	7%
	5	31.8	27.9
	7	25.1	21.3
	10	20.3	16.3
		Allowed return on equity	
Utility return on equity = 10% (SC = $57 million)		10%	7%
	5	15.1	13.9
	7	11.7	10.6
	10	9.3	8.1

Staff at the Pennsylvania PUC showed how regulatory decisions about return on investment could affect the allowed cost of a particular nuclear generating unit. For the unit in question, full-cost recovery is equivalent to 8.5¢/kWh, reducing the allowed return on equity to 90% of the interest rate on long-term debt lowers the cost to 8.0¢/kWh, allowing zero return on equity lowers the cost to 7.0¢/kWh, and eliminating both return on equity and interest on bond payments (i.e., setting the allowed cost of capital on this unit to zero) cuts the cost to 4.9¢/kWh. The Pennsylvania Office of Consumer Advocate estimated that fully 20% of the SCs claimed by PECO Energy represented a return on investment at traditional rates.

REGULATORY ASSETS

As noted above, regulatory assets include a variety of costs that the utility is obligated to pay in the future that are not yet reflected in rates. These costs can include the phase-in of capital costs for an expensive power plant, the contingent liability associated with future decommissioning of nuclear plants and perhaps fossil plants, payment of deferred income taxes, post-retirement benefits to its employees (pension funds), and other costs that regulators allow utilities to place on their balance sheets for future recovery. RDI estimated that regulatory assets account for about one-fourth of U.S. electric-utility stranded costs.

Controversies can and do arise in estimating regulatory assets, much as they do in estimating generation-related SCs. Arguments occur because not all these costs appear on the utility's balance sheet, regulatory liabilities may offset regulatory assets, and the appropriate time period and discount rate to use in calculating the net present value of these costs is not clear. For example, in a SC case involving PECO Energy, the estimates of SCs related to regulatory assets ranged from $805 million from a group of industrial customers to the utility's estimate of almost $3 billion.

Deferred income taxes is often the largest regulatory asset. This amount represents federal and state income taxes that the utility will have to pay in future years to offset differences between book and tax depreciation lifetimes. In other words, because state and federal tax laws permit corporations to depreciate investments for tax purposes at a faster rate than they do for book purposes, the corporations receive the equivalent of an interest-free loan from the state and federal treasuries. After the assets that gave rise to these tax benefits are fully retired for tax purposes (but not for book purposes), the utility must begin repaying this loan in the form of higher income taxes. This amount is recorded as a regulatory asset.[*]

A utility might claim as stranded costs the regulatory asset associated with its deferred income taxes. This amount, because it is the *nominal* value, rather than the *net present (discounted)* value, of the asset overstates the stranded costs. Use of an appropriate discount rate could reduce the amount by one-fourth.

8. COST MITIGATION

Given the large dollar amounts often associated with SCs, regulators, utilities, their customers, suppliers, and others (including taxpayers [#]) have a strong interest in finding ways to offset these costs. Strictly speaking, stranded costs, because they reflect sunk (i.e., past) costs and future obligations, cannot be "mitigated." However, regulators can allocate these costs among different stakeholders, such as utility shareholders, retail customers, wheeling customers, taxpayers, and wholesale producers. In other cases, costs can be shifted through time.

In some cases, regulators and utilities can find ways to cut operating costs and then use these savings to offset what would otherwise be stranded costs; as a consequence, PUCs generally insist that utility shareholders bear some risk of not recovering all their SCs to be

[*]Analysis of deferred income taxes as a stranded cost is a complicated accounting and tax issue. Treatment of these tax obligations as a stranded cost depends on whether the benefits of accelerated depreciation were flowed through to customers or retained by utility shareholders.

[#]When utilities suffer a financial loss (e.g., by earning a lower return on equity for stranded generating assets or by writing off some of these assets to reduce the amount of SCs to be paid by customers), this loss reduces their federal and state income taxes. Thus, taxpayers typically shoulder about 40% of any SCs borne by utility shareholders.

sure that the utility has a strong incentive to cut costs and improve productivity. The Maine Legislature, in a 1997 law restructuring its electricity industry, conditioned utility recovery of stranded costs on pursuit of "all reasonable means to reduce its potential stranded costs ... The commission shall consider a utility's efforts to satisfy this requirement when determining the amount of a utility's stranded costs." Table 4 lists some of the market, depreciation, rate-design, and cost-reduction strategies that might apply.

In some cases, regulatory decisions affect who bears the costs. Delaying competition protects utility shareholders at the expense of retail customers. On the other hand, rapid and comprehensive implementation of retail competition could bankrupt some utilities, unless the regulatory commission permits recovery of these costs from retail customers.

Other strategies, such as changing the depreciation schedules for generation and transmission assets, affect the timing of these costs rather than their amounts. For example, accelerating depreciation of a nuclear unit would increase rates for today's customers and lower rates for future customers, raising a potential intergenerational equity problem. Renegotiating purchase-power contracts can shift costs from ratepayers and utility shareholders to independent power producers and other wholesale suppliers.

Finally, utilities can cut their costs to produce, transmit, and deliver electricity, as well as their customer-service and administrative costs. Through the use of a sharing mechanism, the state regulator could allocate some of these savings to offset stranded costs with the remainder flowing to retail customers.

The Vermont Public Service Board noted that the transition to competitive electricity markets may provide "substantial *opportunities* for utilities," which can be used to offset what would otherwise be SCs. The Massachusetts Department of Public Utilities also observed that today's utilities have certain competitive advantages, such as "substantial physical assets including plant, equipment, and sites acquired over the monopoly period, and largely financed by ratepayers; and, in some cases, intangible assets, such as name recognition and customer loyalty."

The Vermont Public Service Board also emphasized the utilities' obligations to mitigate SC amounts and offered to provide SC recovery only after all mitigation strategies had been implemented. The 11 mitigation strategies identified by the Board include: renegotiation of power-purchase contracts; buy-out or buy-down of power-purchase contracts; economic operation of existing facilities and contracts; shutdown of uneconomical generating units; renegotiation of fuel-supply contracts; cost reduction; sale of uneconomical assets; write-off or write-down of uneconomical assets; appropriate load growth; exchange of underutilized assets; and refinancing of obligations through low-cost, long-term bonds.

Table 4. Potential SC-mitigation strategies

Action	Effect
Market actions	
Accelerate or delay the start of retail competition	Shift costs to (away from) utility depending on PUC-approved cost-recovery plan; hasten (defer) benefits of competition
Increase electricity sales, either at wholesale or at retail	Lower SCs
Finance options	
Accelerate depreciation schedules for high-cost generating units	Shift costs through time
Slow depreciation rates for transmission and distribution assets to offset faster depreciation of generating assets	Shift costs from generation to transmission and distribution
Write off or write down the amount of assets above market value	Shift costs from customers to utility shareholders
Rate-making options	
Price energy at close to marginal cost, increasing monthly customer charge	Increase sales, lower SCs, and improve economic efficiency
Adopt performance-based rates	Shift risks to utility, encourage utility to cut costs, and reduce SCs
Utility-cost reductions	
Improve generating-unit performance by: - Increasing efficiencies - Increasing availability - Lowering O&M costs	Lower SCs
Retire uneconomic generating units	Lower SCs
Renegotiate or buy out expensive power-purchase contracts	Lower SCs, may shift costs to owners of these contracts
Reduce nongeneration costs, assign savings to SCs	Shift savings from transmission and distribution rates to generation

9. COST-RECOVERY AND TRUEUP MECHANISMS

Designing a workable and policy-responsive cost-recovery and trueup mechanism may be the key unresolved issue related to stranded costs. At a philosophical level, policymakers face two extreme choices. The first calls for considerable effort and diligence to develop an a priori and accurate number for *the* stranded-cost amount. Exactly how much money will this utility lose in a fully competitive electricity market because of its generating units, its purchase-power and fuel-supply contracts, and its regulatory assets?

The second choice focuses on the design of cost-recovery and trueup mechanisms* to ensure that, on an ongoing basis, the utility recovers those costs to which it is entitled, no more and no less. In this case, the upfront estimate of the SC amount is less important than in the first case. On the other hand, with this choice, the design of an appropriate mechanism is critically important.

FERC and some PUCs limit SC recovery to those costs that are "legitimate, prudent, and verifiable" as well as nonmitigable. The Montana Legislature required that these costs include only those that "have been previously allowed in rates or, if not previously in rates, ... determined to be used and useful to ratepayers ...." The Nevada Legislature limited recovery to those costs that are "documented in the accounting records" of the utility.

Hanger, a former Pennsylvania PUC Commissioner, suggests "different recovery levels for different types of stranded investments." Commissions can consider the degree of utility-management responsibility for the SCs that exist in each category. In addition, the stranded costs associated with utility-owned generation assets include both a return *of* investment and a return *on* investment; commissions can consider these types of costs differently for recovery purposes. Commissions may allow either no or a reduced return on equity on certain assets contributing to SCs, for example. Alternatively, commissions may allow only a return of capital without any return on investment. Under this policy, shareholders would forego their equity return and might also have to pay the long-term debt return to bondholders.

Some utilities have generating assets whose book values are *below* market prices. Although this situation of negative SCs has received little attention, regulators in some states will have to decide how to allocate these benefits between utility shareholders and retail customers. Presumably, the same principles that determine the allocations for positive SCs should apply to negative SCs. As noted by the staff of the Texas PUC, "In the transition to a competitive retail electricity market, to the extent utilities with *positive* [SCs] are granted recovery of such costs from ratepayers or otherwise, utilities with *negative* [SCs] should likewise be required to pass through to ratepayers the benefits of their low cost generation resources."

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*Cost recovery refers to the method (e.g., an energy or demand charge vs a monthly customer charge) used to collect from customers the amount of stranded costs that the state regulator has determined to be appropriate. Trueup refers to the method used to determine, from year to year, what that amount should be.

POLICY OBJECTIVES

The choice of a suitable trueup mechanism should be based on its ability to meet key public-policy objectives. PUCs might consider the following four broad goals and supporting objectives:

- The utility's operation of, and investment in, its generating resources should be consistent with the actions taken by the owners of similar resources in fully competitive bulk-power markets. Thus, the SC-recovery and trueup mechanism should not affect generation-related operation and investment decisions. This general principle leads to three subsidiary objectives designed to ensure that the utility is treated the same way that other suppliers are treated in competitive generation markets.

  - The utility should be fully responsible for all future avoidable costs. That is, the recovery mechanism should not indemnify the utility for its future generation-related fuel costs, O&M costs, or capital-addition costs; decommissioning costs might be an exception to this rule (Exhibit 2).

  - The utility's earnings should respond to market forces (e.g., electricity prices) in the same way that the earnings do for other suppliers.

  - The utility should face economic incentives to improve its generation productivity and cut costs. Thus, at least some of the money saved by a utility's productivity improvements should be retained by the utility.

- Retail customers should benefit from competition and should face market forces. This general principle leads to two subsidiary objectives, which may conflict with each other.

  - Retail customers should face market-induced price changes.

  - Future (market-based) retail prices for all customer classes should not exceed today's embedded-cost prices during the SC-recovery period.

- Neither customers nor shareholders alone should bear undue risks of over- or under-recovery.

- The mechanism chosen should be simple to understand and to administer. It should not result in the equivalent of heavily litigated, annual rate cases.

Exhibit 2. Role of Avoidable and Unavoidable Costs

Cost-recovery mechanisms should encourage the utility to manage its generating resources in an economically efficient manner. Such decisions should depend on avoidable and unavoidable costs and should not be influenced by the form of SC recovery. Consider an example to see how these cost components should affect future decisions on generator operation or retirement and the amounts of SC recovery (Table E2). A 200-MW unit has variable costs (fuel plus nonfuel O&M) of 2.1¢/kWh, avoidable fixed O&M costs of \$10/kW-year, and unavoidable fixed capital costs of \$20/kW-year. Thus, SCs should be capped at \$4 million/year (200 MW × \$20/kW).

The economic fate of this unit should depend on its output (GWh produced) and on the price it receives for that output. Assume that market conditions allow this unit to sell its output on the spot market for 2500 hours a year at an average price of 3.0¢/kWh. The unit's revenues amount to \$15 million. Variable costs (200 MW × 2500 hr × 2.1¢) account for \$10.5 million, leaving \$4.5 million to cover fixed costs. This \$4.5 million is greater than the \$2 million avoidable fixed cost, which suggests that it is economical to operate this unit. The \$2.5 million remaining after avoidable fixed costs are paid can be used to offset SCs. Thus, this unit has stranded costs of \$1.5 million this year.

If the region had more generation online than implied above, the unit might be able to operate for only 1500 hours a year, receiving only 2.6¢/kWh for its output. In this case, the unit's revenue of \$7.8 million would leave only \$1.5 million after covering variable cost. This amount is insufficient to pay for avoidable fixed costs, suggesting that this unit should be shut down. (Whether the utility should permanently retire the unit or mothball it for a few years would depend on its assessment of future market conditions.) In this case, the SCs are capped at \$4 million, the unavoidable capital costs. The utility would *not* recover the full \$4.5 million loss it would incur if it continued to operate the unit.

If, on the other hand, the amount of capacity in the region is limited, the unit might operate for 3200 hours at 3.1¢/kWh. In this case, revenues would be sufficient to cover all the unit's costs, and SCs would amount to −\$400 thousand (i.e., a negative SC). This amount could be used to offset losses associated with other generating units.

This example shows that the amount of SCs associated with a particular generator depends on the interactions between that unit and the competitive bulk-power market. It also suggests that regulators should choose a recovery mechanism that does not distort what would otherwise be economically efficient decisions concerning the operation, shutdown, or retirement of the unit.

Exhibit 2. Continued

Table E2. Hypothetical example showing relationship between avoidable and unavoidable fixed costs and allowable stranded costs

	Bulk-power market conditions		
	Base	Excess capacity	Little capacity
		Unit operations	
Hours/year	2,500	1,500	3,200
Price received, ¢/kWh	3.0	2.6	3.1
		Revenues and costs, thousand $/year	
Revenues	15,000	7,800	19,840
Variable cost	10,500	6,300	13,440
Net revenue	4,500	1,500	6,400
Avoidable fixed cost	2,000	2,000	2,000
Net revenue	2,500	-500	4,400
Unavoidable fixed cost	4,000	4,000	4,000
Net revenue	-1,500	-4,500	400
Maximum allowable SC	1,500	4,000	0

CANDIDATE MECHANISMS

State regulators and legislators have many choices for cost-recovery and trueup mechanisms, including:

- *Securitization* is the issuance of bonds, for which the state guarantees that customers will pay the interest and principal. Because of this state guarantee, these bonds are low in risk and therefore carry an interest rate lower than that for corporate bonds. The utility receives the full bond proceeds when the bonds are issued and then, on behalf of the bondholders, collects interest and principal payments from its customers on a monthly basis. The only reconciliation associated with such bonds occurs if the monthly collections of principal and interest payments do not match those called for in the bonds; that is, the bondholders have a virtually ironclad guarantee of recovering their investment from electricity consumers within the utility's jurisdictional boundaries. (Adjustments to the monthly payments are symmetric. That is, if retail electricity use is higher than expected, the payments are reduced, and vice versa.)

- *Exit fees* require departing customers to make a lump-sum payment (or a periodic stream of payments during a defined transition period with the same net present value as the lump-sum payment) to the utility for the SCs associated with those customers' decisions to purchase energy and capacity resources elsewhere. This is the approach that FERC uses for recovery of wholesale stranded costs that arise from its open access policy.

- An *up-front determination* of the amount of SC that a utility is entitled to recover and a cost-recovery mechanism that ensures that the utility, over time, recovers no more and no less than that predetermined amount. Periodic trueups and balancing accounts can be used to adjust the monthly charge that customers pay for changes in load growth and any other factors that affect the amount of money so recovered. Because this approach predetermines the amount of utility recovery, it should be simple to administer.

- *Full (100%) recovery of SCs*, agreement that the utility will recover dollar-for-dollar its actual SCs. This approach requires periodic (e.g., annual) trueups to ensure that the utility recovers fully the difference between its embedded costs of generation and the market price of generation. Such a system provides no incentive to the utility to cut costs and improve productivity.

- *Prior specification of the retail price* for generation services, perhaps capped at the current regulator-approved price or cut by a predetermined percentage. The utility is then allowed to collect SCs from its customers on the basis of the difference between the set price and its actual, ongoing costs of generation. No trueup is conducted with this approach.

- A *performance-based determination* of allowable generation costs that the utility can recover. This approach allows for continuing reductions in the price that retail customers pay for generation services. Such a mechanism can be simple (e.g., a 2% per year reduction in allowed generation costs) or sophisticated, with allowed costs tied to regional fuel prices and the performance of the utility's generators (e.g., unit heat rates and availabilities, and O&M costs tied to indices of industry performance). Again, no formal trueup is needed here because it occurs automatically, based on the particular mechanism chosen by the PUC.

- An after-the-fact reconciliation of SCs with a *shared-savings mechanism*. In this case, the utility recovers a predetermined percentage of the difference between its embedded costs of generation and the market price of generation. This system provides a clear incentive to the utility to cut costs and improve productivity.

None of these approaches satisfies all the objectives that have been suggested. The first three mechanisms [securitization, exit fees, and use of a nonbypassable monthly charge (sometimes called a wires charge) paid by all customers to recover a predetermined amount] have similar characteristics. Specifically, they are, in principle at least, simple to administer, primarily because they involve no trueup or the amount of trueup is simple to determine. On the other hand, they provide no direct benefits to customers and may offer no incentive to the utility to cut its future generation costs. As FERC noted, "The primary rationale offered in support of a snapshot approach is certainty; the primary rationale offered in support of true-ups is accuracy."

Assurance that the utility will recover 100% of its ongoing stranded costs insulates the utility from competitive generation markets and therefore provides no incentive for the utility to improve its productivity. On the other hand, full recovery can be simple to administer, and it provides revenue stability to the utility.

The last three methods listed above can provide productivity incentives to the utility and price reductions to customers. However, these methods are more complicated to design and implement and could lead to litigation every time the method is applied (e.g., the equivalent of an annual rate case). In addition, these methods place the utility at risk for nonrecovery of some of the SC amount.

10. SUMMARY

State regulators and legislators must pay explicit attention to stranded costs, primarily because of the large dollar amounts involved in many states. Ignoring this topic will inevitably lead to delays in (1) restructuring the electricity industry, (2) increasing customer choice, and (3) allowing competitive forces to drive down electricity costs and prices. State policy makers should recognize that the large dollar stakes associated with stranded costs can lead to situations in which self-interest, rather than the broad public good, will dominate discussions, debates, and litigation over restructuring.

The amount of stranded costs facing a utility or its customers is not a single value waiting to be discovered by smart, hardworking analysts. It is a value that, to a large extent, is created by markets as well as regulators, utilities, their customers, and their suppliers. The amount that needs to be explicitly allocated among various parties depends on many factors, some of which can be managed by the parties involved. Some of these factors, especially competitive generation prices, may be largely outside the control of those directly involved with the particular utility. As the Texas PUC noted, "The degree to which investments are ultimately stranded will depend upon changes in the market price of electricity, the speed with which markets become effectively competitive, tax implications of potential restructuring options, mitigation efforts by the utilities, and the actions of utilities, the Legislature and the Commission regarding electric industry restructuring."

Whether or not a utility should receive 100% of its stranded costs may not be a particularly important issue to resolve because it begs the question "100% of what?" A more important issue is deciding what costs legitimately should be considered stranded. In the end, a utility may do better getting 75% of its request than getting 100% of what a strict regulator determines to be legitimate, verifiable, and nonmitigable stranded costs.

Some of the stranded-cost issues discussed here are analytical. But others are primarily policy issues. In particular, the definition and determination of stranded-cost amounts and the allocation of stranded costs among the different stakeholders are critical policy issues on which legislators and regulators will play a key role.