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**Transition-Cost Issues for a
Restructuring U.S. Electricity
Industry**

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ENERGY DIVISION

TRANSITION-COST ISSUES FOR A
RESTRUCTURING U.S. ELECTRICITY INDUSTRY

LESTER BAXTER, ERIC HIRST, and STAN HADLEY

March 1997

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SUMMARY

The U.S. electric-utility industry is in the midst of major changes. These changes include deintegration of the industry and substantial increases in competition within the generation and customer-service sectors of the industry. A major consequence of these changes is the exposure of transition costs. These costs, which could amount to \$100 to \$200 billion nationwide, reflect the differences between the regulated prices for electricity generation and the prices that might occur in fully competitive power markets. These above-market costs are associated with past costs (e.g., in construction of power plants that turned out to be expensive or to provide more capacity than needed) and future obligations (e.g., long-term fuel-supply and power-purchase contracts).

The large financial stakes, comparable in magnitude to the total value of U.S. electric-utility common stock (roughly \$190 billion), guarantee controversy. Debates occur over transition-cost amounts; analytical and market methods to estimate these costs; the assets and liabilities to include in such calculations; the assumptions used in developing these estimates; approaches that can be used to offset at least some of these costs; the ultimate allocation of the remaining costs among utility shareholders, different classes of retail customers, independent power producers and other wholesale suppliers, and taxpayers; and appropriate cost-recovery mechanisms. This report discusses each of these issues.

Competition generally does not create transition costs; rather, it exposes these costs and makes them a visible source of conflict among different market participants arguing over who will bear these costs in the future. We call these costs transition costs to emphasize the fact that they are not a permanent feature of a competitive electricity industry. Once dealt with—no easy task for regulators—they will no longer be an issue.

Utilities and regulators can use a variety of approaches to calculate transition costs. We categorized these approaches along three dimensions. The first dimension is the use of administrative vs market procedures to value the assets in question. Administrative approaches use analytical techniques to estimate transition 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 the restructuring of the electricity industry. The third dimension concerns the level of detail involved in the valuation, what is often called top-down vs bottom-up valuation.

Regardless of the method used to estimate the amount of transition costs, one must make certain assumptions. Although many factors affect the determination of transition costs, only

a few factors make a big difference. The most important factors include future market prices of electricity, utility marginal costs of production, when retail wheeling begins, extent of retail wheeling, amount of utility regulatory assets, and utility fixed production costs. Of these critical factors, some can be influenced by the utility and some by the state regulator, and some are essentially beyond the control of either party. The regulator can affect the start date and extent of wheeling, although market forces may overwhelm regulation where large price disparities exist; and utilities can seek to cut their fixed and variable production costs. But wholesale prices are largely independent of utility or regulator actions.

Strictly speaking, transition costs, because they reflect sunk (i.e., past) costs and future obligations, cannot be mitigated. However, regulators can allocate these costs among different groups or shift them over time. In some cases, regulators and utilities can find ways to cut operating costs and can then use these savings to offset what would otherwise be transition costs.

To date, governments have differed in their approaches to allocating the remaining, non-mitigable transition costs. The Federal Energy Regulatory Commission and the state of California, perhaps in recognition of the key role that today's utilities will play in the transition to a fully competitive electricity industry, decided to allow utilities the opportunity to recover their legitimate, verifiable, nonmitigable, and prudent transition costs. The Vermont and New Hampshire regulators, on the other hand, emphasized the importance of utility mitigation of as much of the transition costs as possible. These two states, in balancing the interests of utility shareholders and retail customers, favored customers more than did FERC and California.

Having decided how much of its transition costs a utility should be allowed to recover, regulators need to implement workable cost-recovery mechanisms. Such mechanisms should encourage competition in the generation sector and should neither favor nor hamper the decisions of utilities, independent power producers, and customers. In other words, the cost-recovery mechanism should not affect supplier decisions on electricity production and should not affect customer decisions on how much electricity to consume and from whom to buy that electricity. Cost-recovery mechanisms should give utilities the same incentives that other electricity suppliers face to cut costs and innovate.

LIST OF ACRONYMS

BU	Bottom up
FERC	Federal Energy Regulatory Commission
IREMM	Inter-Regional Electric Market Model
KS	Keep sale
LS	Lose sale
NPV	Net present value
O&M	Operations and maintenance
PBR	Performance-based ratemaking
PUC	Public utility commission
QF	Qualifying facility
RDI	Resource Data International
ROE	Return on equity
RW	Retail wheeling
SCE	Southern California Edison
T&D	Transmission and distribution
TC	Transition cost
TD	Top down

BACKGROUND

Transition costs (TCs) are the potential monetary losses that electric-utility shareholders or other parties might experience because of structural changes in the electricity industry. Roughly speaking, TCs are based on the difference between regulated retail electricity prices for generation services and the competitive-market price of power. 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 all the costs of producing and delivering electricity. In a competitive electricity market, the frequent interaction of buyers and sellers, rather than regulators, will set prices. If these prices are below embedded costs, then transition costs will occur. The Texas Public Utility Commission (Texas PUC 1997) refers to these costs as "the historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market."

Figure 1 is a simple example of transition costs associated with utility-owned generating units. The left bar shows the expected annual revenue requirements in 1998 for the generating units owned by Central Power & Light (Orans 1996). These costs include capital (depreciation, interest payment on bonds, return on common equity, and taxes), fuel, and operations and maintenance (O&M) costs. Traditionally, these costs are reviewed by state regulatory commissions. If approved, these costs are then incorporated into the rates that the utility is allowed to charge its customers. In this example, the utility has capital costs that are equivalent to 2.1¢/kWh, fuel costs of 1.6¢/kWh, and O&M costs of 0.7¢/kWh, leading to a total embedded cost of generation of 4.4¢/kWh. By comparison, the estimated market price of power in Texas is only 2.0¢/kWh for 1998. These numbers suggest that the utility would lose the equivalent of 2.4¢/kWh if it sold electricity to its retail customers at competitive market prices. Because the estimated market price is below the sum of fuel plus O&M costs, the utility might choose to shut down some of its high-cost generating units to minimize its losses.

Failure to fully and fairly consider such costs could be a major impediment to industry restructuring. Studness (1996) argues that "Recovery of stranded investment is clearly the central point of contention in the debate over utility competition. ... Utilities argue that the 'regulatory compact' entitles them to full recovery; customers claim that no such entitlement exists." Similarly, the California PUC (1995) recognized the critical role that transition costs play in restructuring the electricity industry "to assure the continued financial integrity of California's investor-owned utilities, and give them an opportunity to be vital participants in the restructured market" And the Federal Energy Regulatory Commission (FERC 1996a), in its final rule on open-access, nondiscriminatory transmission service, devoted 187 pages of its 780-page order to TCs. FERC noted that "the recovery of legitimate, prudent and verifiable

stranded costs is critical to the successful transition of the electric industry to a competitive, open access environment."

Fig. 1. Comparison of the embedded cost of generation with the estimated market price in 1998 for Central Power and Light.

Transition costs can include four classes of costs (Niagara Mohawk Power Corp 1994):*

- Assets, primarily expensive power plants and excess generating capacity;
- Liabilities, primarily power-purchase contracts, fuel-supply contracts, and deferred income taxes;
- Regulatory assets (whose value is based on regulatory decisions rather than on market forces), including deferred taxes and expenses for power plants and costs for demand-side management programs that regulators allow utilities to place on their balance sheets; and
- Public-policy programs, including tax collection, environmental compliance beyond that required by law, demand-side management programs paid for by all customers, special

*Transition costs can also include the costs of implementing the transition to a competitive electricity industry, including employee retraining, appraisal and sale of assets, and taxes associated with the sale of assets.

programs for low-income customers, and support for energy research and development (unlike the other three categories, the costs in this category are current, not sunk).

Figure 2 shows the estimates of annual TCs developed by New England Electric (Jesanis 1996). For this utility, fossil generation and power-purchase contracts are the key contributors to potential TCs, accounting for about three-fourths of the total \$4 billion. The figure also shows that these losses decline steadily with time. Although the figure shows estimates only through the year 2010, the utility estimates potential losses through 2025 because of some long-lived power-purchase contracts and nuclear-decommissioning costs.

Fig. 2. New England Electric estimates of its transition costs.

Several entities have estimated the amounts of TCs that individual utilities might face (Baxter and Hirst 1995; Fremont et al. 1995; Prudential Securities 1996; Resource Data International 1994 and 1996; Watt, Lapson, and Bloomberg 1995). For example, Moody's Investors Service (Fremont et al. 1995) analyzed data for 114 utilities (representing more than 80% of the assets of all U.S. investor-owned utilities). They estimated that TCs could range from \$50 to \$300 billion, with the most likely value of \$138 billion, equivalent to almost 90% of shareholder equity. (All monetary values in this chapter are in 1994 dollars.) An update of the Moody's analysis (with the same method but with 1995 data rather than 1993 data) led to a national estimate of \$133 billion (Hackett, Cohen, and Abbott 1996). Of the 26 utilities with TC estimates greater than \$2 billion, 16 had TCs greater than shareholder equity. All told, 34 of the 116 utilities included in Moody's analysis had potential transition costs in excess of their

equity (Fig. 3). Oak Ridge National Laboratory developed national after-tax estimates for investor-owned utilities that ranged from \$16 billion to \$268 billion and suggested that the most plausible range is \$72 billion to \$104 billion (Baxter and Hirst 1995). Prudential (1996) developed a TC estimate of about \$30 billion.

Resource Data International (RDI 1996) estimated a nationwide TC of \$184 billion, well above their 1994 estimate of \$158 billion. Of this total, \$134 billion is accounted for by investor-owned utilities, \$29 billion by municipal utilities, and \$20 billion by cooperatives. (Most of the other estimates we reviewed dealt only with investor-owned utilities.) Utility-owned generating units account for the largest share of the \$184 billion, \$65 billion. RDI calculates the nationwide TC for nuclear units at almost \$79 billion, offset by a negative TC for fossil and hydro units of \$15 billion. Regulatory assets account for \$45 billion of TCs, power-purchase contracts with nonutility generators for \$38 billion, power-purchase contracts with other utilities for \$49 billion, and sales contracts for a negative \$11 billion. California, New York, and Texas together account for more than 40% of U.S. TCs, according to this analysis. The states with the highest ratio of TCs to retail sales are Connecticut, New York, New Jersey, Illinois, California, Massachusetts, and Pennsylvania.

RDI also identified several utilities that had below-market costs, leading to a total negative TC 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. States with zero or negative TCs include Utah, Tennessee, Oregon, Oklahoma, Washington, Minnesota, Kentucky, Wisconsin, Iowa, and Montana.

The estimates developed by different entities, at different times, with different metrics and assumptions differ from each other. For example, the estimate by Prudential Securities is considerably lower than the other national estimates cited above. This difference is at least partially caused by Prudential's including fewer utilities in its analysis, assuming that only future revenues from commercial and industrial customers are at risk, and using a higher market price for electricity that includes capacity. Studies that use similar assumptions, even though their specific estimation approaches differ, often yield closer results. The correlation coefficient (r) between estimates of transition costs from Oak Ridge National Laboratory and from Moody's 1995 study is 0.84, for example, for the 111 companies in both analyses.

Our review of these various estimates of transition costs leads to several conclusions. First, although the methods used and results obtained differed across these analyses, they generally suggest that the potential losses associated with TCs are substantial. Second, they show that the losses are unevenly spread among utilities and regions. Third, the range of recent estimates of the nationwide losses is much less than the range estimated a few years ago; this reduction in range is a consequence, we believe, of growing agreement on what assets and liabilities should be considered in calculating transition costs. Fourth, despite the narrowing of recent national estimates, the results obtained, even for the same situation, can differ

substantially, depending on the perspective of the entity making the estimates, the analytical approach used, and the assumptions made. To illustrate, Fig. 4 shows several estimates of the transition costs that Central Power & Light might face (Orans 1996). These estimates differ by a factor of more than three, with the utility's estimate the highest and the large industrial customers' estimate the lowest. This large range is a consequence of the use of different assumptions, methods, and perspectives.

A full treatment of TCs would consider (1) appropriate ways to calculate TCs; (2) estimates of the TC amounts for individual utilities, states, regions, and the United States as a whole; (3) strategies to mitigate these amounts; (4) allocation of the remaining TC among utility shareholders, different classes of customers, independent power producers, and taxpayers in general; and (5) the mechanisms used to allocate or recover TCs. This report addresses each of these topics. Chapter 2 presents an economic framework for the definition and discussion of TCs. Chapter 3 discusses various analytical and market-based approaches to calculating TCs. Chapter 4 suggests several criteria that regulators and others can use to assess the applicability of different methods to calculating TC amounts. Chapter 5 presents several specific methods to calculate TC amounts and assesses these methods against the criteria presented in Chapter 4. Chapter 6 analyzes the sensitivity of TC results to changes in input assumptions, primarily to identify the critical factors in determining TC amounts. Chapter 7 discusses several strategies to recover or reduce transition costs. Chapter 8 discusses policy and legal issues associated with the allocation of remaining TC amounts among the different stakeholders. Chapter 9 describes an approach to integrating TC recovery with competitive generation markets. And Chapter 10 summarizes the key findings from this work.

Fig. 3. Moody's estimates of transition costs relative to shareholder equity for 116 U.S. investor-owned electric utilities.

Fig. 4. Alternative estimates of the transition costs faced by Central Power & Light Company.

THE ECONOMICS OF TRANSITION COSTS

Traditionally, state regulators have used cost-of-service methods to establish retail rates. Under cost-of-service rate making, regulators give utilities the opportunity to recover all the prudent costs the utility incurs to satisfy the demand for electricity services within its franchise area. These costs include the return of (depreciation) and return on investments in utility plant (generation, transmission, and distribution) and the ongoing costs of fuel, power purchase, and O&M. Many of these costs are considered sunk or embedded because they have already been incurred or reflect obligations to incur future costs. (Costs that are not sunk include short-term or avoidable fuel and power-purchase costs.) In contrast, prices in a competitive market more closely reflect marginal production costs (the additional costs that suppliers incur to meet current and future demand).

The sunk costs of generation for many utilities lead to higher rates than competitive wholesale prices. This situation has not always prevailed in the electricity industry. During much of the 1970s and early 1980s, utility marginal costs were greater than their average revenue requirement. Today, however, when embedded generation costs exceed the competitive market price for generation services, the potential for TCs arises.

Transition costs are most likely to occur when utility rates are above market prices for generation services. Under these circumstances, customers will be motivated to purchase from lower-cost sources and utilities will be motivated to reduce rates. Rose (1996) presents a simple comparative model that illustrates the implications these circumstances have for TCs. Figure 5 presents a situation for a hypothetical utility and an alternative power supplier. To simplify, we remove from this example the costs for transmission, distribution, and other nongeneration costs. Under most circumstances, the utility will be able to recover these costs because it will remain the only supplier of such services (i.e., restructuring proposals continue to envision the transmission and distribution of electricity as monopoly services). These costs will probably be recovered through access fees or through regulated rates.

The MCG_u curve in Fig. 5 represents the utility's marginal cost of generation and its price for generated electricity under the new competitive regime. The figure shows the right portion of the marginal cost curve when the utility's economies of scale are exhausted. The average cost of generation (ACG_u) is also the utility's price curve under the existing embedded-cost pricing regime. In this example, the utility's marginal generation costs exceed its average generation costs only at high levels of production. The utility will only recover its fixed generation costs when prices equal or exceed its average generation costs. The utility's average

variable cost of generation curve ($AVCG_u$) lies below its average generation cost curve. The difference between these two curves reflects the utility's average fixed costs of generation.

Fig. 5. Comparative static model of utility transition costs, adapted from Rose* (1996).

The final curve depicts a competitor's marginal cost of generation (MCG_a). This curve, drawn with its origin at the right axis, assumes a generally flat slope over the initial range of output and then gradually increases. This curve can also represent the market price of electricity from multiple suppliers. Finally, the horizontal axis reflects different combinations of utility and competitor power supplies that meet an incremental demand for electricity. At the right-most point (q_u), all the demand is met by the utility, while at the left-most point (q_a) all the demand is met by the competitor. Point q^* represents the optimal combination of generation supply for this level of demand, the point where utility marginal costs and supplier costs are equal.

The difference between the utility's average generation costs and its average variable generation costs to the right of q^* are unrecoverable when generation services are provided by

*As Rose explains, this figure is simplified to illustrate certain key features of TCs. Most importantly, the figure represents a single small increment in time, perhaps a single hour, and does not reflect the more complex relationships among utility costs, prices, and market prices over longer periods. Also, the figure implies that the utility is selling its generation output at marginal cost. If this was the case, the utility will also be unable to recover some or all of its average fixed generation costs when MCG_u is less than ACG_u , as depicted on the left side of Fig. 5, unless the market price for generation is greater than ACG_u .

the competitor. This area includes the utility's average fixed generation costs. These latter costs are the TCs faced by the utility, assuming that the utility does not sell this potential output in another market. The utility does not face any other generation costs when it is no longer supplying generation. Thus, the utility does not incur the portions of average generation costs related to variable costs, such as fuel and variable O&M, when it is not generating electricity. The utility's average fixed generation costs remain however, even when a competitor is generating the electricity. Thus, Fig. 5 depicts the amount of TCs when the utility previously met all demand (q_u), but now generates only the optimal quantity (q^*). In addition, the difference between the utility's average generation costs and its marginal generation costs to the left of q^* are unrecoverable when generation services are priced at the utility's marginal cost.

This perspective illustrates that two categories of costs may cause a utility's total price for delivered electricity to exceed the competitive market price. The first, the amount that a utility's rate exceeds its marginal generation costs, includes nongeneration costs or costs that do not contribute directly to the utility's cost of generating electricity. Transmission and distribution are the most prominent examples of these nongeneration costs, but costs for public-policy programs may also be included here. Rose (1996) also includes excess-capacity costs in this first category. These excess-capacity costs are associated with generating plants that operate well below their intended capacity factors. The second category, the amount that a utility's marginal generation costs exceed a competitive market price, includes direct generation costs, such as fuel costs and O&M.

We make several observations about TCs based on this economics perspective:

- the presence and amount of TCs depend on the marginal generation costs for the utility and alternative supplier and on the relationship between the utility's marginal and average generation costs;
- TCs can occur when a competitor's marginal generation costs are below the utility's marginal generation costs or when the utility's marginal generation costs are less than its average generation costs (and the utility is pricing at its marginal cost);
- when the competitor's marginal generation costs are less than the utility's, then the potential generation-related TCs equal the utility's average fixed generation costs (if the utility does not sell this electricity in another market);
- when the competitor's marginal generation costs are less than the utility's, then the potential generation-related TCs equal the utility's average generation costs minus the market price for generated electricity (if the utility does sell this electricity in another market);

- reductions in the utility's marginal generation costs will reduce the probability of economical bypass to competitive suppliers and, thus, of incurring transition costs, except when such reductions increase the amount that marginal costs are below average costs;
- properly structured competitive markets will motivate utilities to reduce generation costs and thereby reduce their TCs over time;
- competitive markets will define the market price for electricity (which will equal the marginal cost of electricity generation if the market is efficient) and the level of TCs; and
- as a result, transition costs are not static but will change over time, depending on changes in the competitive market price for electricity and the utility's generation costs.

One additional complication that some utilities face is that not all generation costs are included in today's average cost of generation. Today's average costs reflect sunk costs and historical obligations that extend into the future. Two important historical obligations, long-term power-purchase contracts and fuel-supply contracts, are included in today's average costs. Two other future costs may not be fully included and are not avoidable. These are the costs associated with the decommissioning of nuclear power plants and the environmental mitigation or restoration costs associated with past utility actions. Because these two classes of costs are largely unknowable today, it is not possible to accurately include them in today's TC estimates.

ESTIMATION APPROACHES

Estimation methods are important for three reasons. First, the TC estimate one obtains depends strongly on the method used to develop that estimate. (TC estimates also depend strongly on the assumptions made, as discussed in Chapter 6.) Second, the literature provides few details on different estimation methods; indeed, some of the references cited above provided incomplete explanations of their estimation approach, data sources, and key assumptions. Third, regulators need simple methods they can use to check the reasonableness of the results utilities present to them.

Utilities and regulators can use a variety of analytical approaches to calculate TCs. San Diego Gas & Electric (1994) developed a useful typology of methods to estimate TCs (Table 1). This framework considers three categories: administrative vs market valuation, ex ante vs ex post valuation, and TD vs BU valuation. Administrative approaches use forecasting, modeling, or other analytical techniques to estimate TC amounts. Market valuation relies on the purchase price of particular assets to determine the market value of assets, although analysis may be needed to compare market and regulated values. Ex ante approaches determine TC amounts before restructuring of the electricity industry is completed, while ex post approaches delay the valuation until restructuring has been achieved. See Baxter (1995) for an assessment of these eight approaches. TD methods treat the utility as the unit of analysis, whereas BU methods focus on individual assets and liabilities.

Table 1. Alternative ways to compute transition costs

	<u>Market valuation</u>		<u>Administrative valuation</u>	
	Ex ante	Ex post	Ex ante	Ex post
Bottom-up	Assets sold at auction	After-the-fact purchase-price adjustment	Asset-by-asset value projections	Assets valued after restructuring
Top-down	Bundles of assets spun off	Deferred valuation of spun-off assets	Projection of regulated rate by customer class	After-the-fact adjustment of regulated prices

Source: San Diego Gas & Electric (1994).

MARKET VALUATION

With market-valuation methods, potential investors conduct their own, private analyses of market value to determine their bid prices for individual generating stations. This approach does not require public decisions on valuation methods, assumptions, or results.

The California PUC (1995) proposed that the utilities divest themselves of up to half of the fossil-fired generation they own, in part to help estimate transition costs. Wilson (1996) advocates the sale of assets as a preferred way to determine their true market value. Of course, a utility would have to sell *all* its generating assets, both those with above-market value as well as those with below-market value to determine the amount of TCs it faces (see the discussion below on administrative valuation). Nuclear and hydro units, however, pose special problems, as indicated by both the California PUC and Wilson.* In October 1996, Pacific Gas and Electric announced its intention to sell four power plants (with 3059 MW of capacity and a book value of about \$400 million) by the end of 1997 (Salpukas 1996). Southern California Edison and New England Electric also plan to sell some or all of their generating assets.

Lesser and Ainspan (1996) note that administrative valuation requires up-front estimates of future market prices for electricity, which "will invariably be incorrect, [and therefore] the amount recovered by utilities will either be too much or too little." Use of periodic true ups also poses problems "because it requires continued definition of two key variables: the market price and the embedded price at a given time." They believe that several market prices will exist at the same time and, as evidence, note the multiplicity of prices for an airplane seat for a particular flight. Defining regulated costs may also be difficult given the interaction between such costs and utility cost-reduction efforts. For example, pressure from the regulator and from competitive markets may induce a utility to cut its overall heat rates, reduce its O&M costs, and take other actions that reduce its costs to produce electricity.

The sale price obtained through an auction, by comparison, *defines* the current market price of an asset. That price will reflect the buyer's estimate of the net present value (NPV) of the revenues generated by the asset (the product of electricity generation and the time-varying market price of power in this case) minus the ongoing costs of the asset (fuel plus O&M) plus any salvage value. An auction eliminates the need for regulators to estimate future production, book value, or market prices of electricity. All that is left to the bidders. Lesser and Ainspan cite the Federal Communications Commission's auction of radio-frequency rights as an example of how such auctions can be conducted. If the structure of the future bulk-power market is undefined at the time of the asset sales, however, the prices bid might be low because of what

*Utilities may find it difficult to sell nuclear units because of the contingent liabilities associated with the costs of decommissioning and long-term storage of nuclear wastes. Utilities may have difficulty selling hydroelectric units because the licenses they have from FERC to operate these facilities often include substantial nonpower, public-purpose functions, such as recreation and flood control. Of course, utilities may still sell the output from these facilities.

the Texas PUC (1997) called "the systemic risk of an unstable market structure rather than the risk inherent in each asset ... [which] could lead to substantial undervaluation of generation assets."

All the generation in a region could be auctioned simultaneously over a period of several months. Potential bidders would have to demonstrate their financial viability by posting "earnest money" on all generating units that they wished to bid on. The regulator would limit the amount of capacity that any single bidder could purchase to prevent horizontal-market-power problems. To promote an efficient auction, the current owners of these generators would be required to provide detailed information about these resources before the auction began. And potential bidders would have the right to conduct their own audits of these facilities. Bidders would offer their bids through a computer, which would post the highest bid for each generator at the end of each round of bidding. During the next round, only those bidders willing to offer more than the highest bid during the previous round would be permitted to participate. The bidding would stop when no one was willing to bid more. The Federal Communications Commission found that it took 40 to 100 rounds of bidding, with one or two rounds per day, to complete its auctions.

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.

When considering the specific market-valuation approach to use, the potential tax implications should be assessed (Deloitte & Touche 1996). 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 (Office of Ratepayer Advocates 1996). 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

O&M contracts, plant output, or supplemental services. Regulators must then separate the payment for the asset itself from these other purchases.

ADMINISTRATIVE VALUATION

Administrative-valuation approaches use analytical techniques 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. Transition costs arise when a plant's operating income does not cover its fixed costs. In contrast, a plant with operating income in excess of its fixed costs (i.e., a positive net income) 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 TCs.

A BU, *ex ante*, administrative approach would involve 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 TCs 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* TCs. 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* transition costs. (A similar situation occurs with long-term obligations, such as power-purchase and -sale contracts. A power-sale contract with a price above or a power purchase contract with a price below the market price of power reduces TCs.) Calculating the return provided by each generating unit involves detailed production-cost simulations for both the utility in question and the surrounding utilities and independent power producers. These simulations would show the number of hours each year that each generating unit operates, its variable production costs, the market price of power that hour, and, from these numbers, the profitability of each unit. Such calculations require thousands of assumptions concerning present and future customer locations, loads, load shapes, and peak loads; transmission-system operation, expansion, constraints, costs, and pricing rules; operating costs and performance of all existing and new generating units; fuel prices; government decisions on siting and environmental restrictions for new power plants and transmission lines; and so on. A BU analysis requires similarly detailed calculations of stranded liabilities (especially power-purchase and fuel-supply contracts), regulatory assets, and public-policy programs. The method developed by RDI (1994 and 1996) is probably the leading example of a BU method.*

*The Southern California Edison (SCE 1996b) filing discussed in Chapter 5 illustrates the complexities associated with BU methods. SCE estimated a small, but positive, TC for its hydro units. This anomalous result is a consequence of two subtle and incorrect assumptions: (1) hydro units generate no revenue from the provision of ancillary services, such as regulation and spinning reserve, and (2) hydro output is sold at the monthly average price of electricity instead of the price that prevails during peak periods. This example also illustrates the information asymmetry between a utility and the other parties in a TC case.

The TD approach, rather than using the individual asset or liability as the unit of observation, treats the utility as the unit of observation. In a TD, *ex ante*, 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 BU 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 TC situation. FERC's (1996a) revenues-lost approach is a TD method.

A key issue facing regulators is the usefulness of TD methods. If these methods yield accurate results (i.e., are consistent with those produced by BU methods), then commissions can avoid the complications associated with the BU methods. If, however, the TD methods produce results that are biased or inaccurate, their usefulness will be greatly limited. Regulators need to understand the contribution of methodological differences to cost estimates, especially when TC estimates are high.

The accuracy of TD methods depends largely on how the utility responds to retail competition (Hirst, Hadley, and Baxter 1996a). Faced with retail competition, a utility can lose the sale (LS) or it can lower its price to keep the sale (KS). Analytically, computing the KS value of TC is simple; indeed, the TD and BU methods yield identical results for the KS option.^{*} However, calculating TC for the LS option is much more complicated because its value depends on how the utility's power plants and power-purchase contracts interact with the bulk-power market. Because interactions with the bulk-power market dominate analysis of the LS option, TD methods perform poorly if the utility loses the sale. The KS and LS options yield the same estimates of TC if bulk-power markets are efficient. In other words, if the utility and its RW customers face the same transmission constraints and the same charges for losses and ancillary services, then the losses are the same regardless of whether the utility keeps or loses the sale.[#]

Transition costs can be assessed from at least two perspectives: (1) the utility, assuming that customers face the same prices they would have faced without retail wheeling (RW), and (2) remaining retail customers, assuming that the utility's earnings are unaffected by RW. In reality, neither utility shareholders nor retail customers are likely to bear 100% of the TCs (see Chapter 8).

^{*}The KS approach provides perhaps the most useful reference point for estimation because it assumes rational behavior by consumers and producers and the existence of efficient markets.

[#]In other words, the difference between TD and BU estimates is a function of quantity risk. The amount of generation a utility can sell will depend on regional load growth, the amount of generating capacity in the region, transmission capacity and prices, market design, and market inefficiencies.

If the utility bears all the losses, its costs are equal to the NPV of the differences in net income between the no-wheeling and RW cases:

$$TC = NPV \sum_{t=1}^T (\text{Net income}_{\text{Base},t} - \text{Net income}_{\text{RW},t}) , \quad (1)$$

where the NPV is calculated at the utility's return on equity for the t years 1 through T . Determining T is a difficult policy choice because the annual values of TCs can be positive for several years and then turn negative. Net income is the difference each year between the utility's revenues and its expenses, where expenses include all operating costs, depreciation, taxes, and interest payments on bonds.

If the utility keeps the sales at risk, its earnings loss (change in net income) is:

$$(1 - \text{Income tax rate}) NPV \sum_{t=1}^T \sum_{j=1}^N [\text{kWh}_{\text{RW}tj} \times (\text{Utility total production cost/kWh} - \text{Market price})_{tj} + \text{Rate-design adjustments}_{tj}] , \quad (2)$$

where j refers to one of the N customer classes and $\text{kWh}_{\text{RW}tj}$ is the annual sales loss that the utility experiences because of RW.

The first term in Eq. 2 inside the summation sign is the amount of money lost because the utility now collects from wheeling customers only the market price for electricity, whereas before it collected the total cost (fixed plus variable costs) of production and purchased power. The estimates of average utility production cost and market price must be consistent with each other. Specifically, all prices and costs must be measured at the same level in the transmission and distribution (T&D) system (e.g., at the generator busbar) to consistently reflect electrical losses in the T&D system, and they must include only comparable costs (e.g., generation only with T&D costs excluded). Also, both annual averages must be weighted by electricity consumption, not by time. Because marginal cost and wholesale price generally increase with demand, consumption-weighted values are roughly 5 to 10% higher than time-weighted values.

The second term represents any losses associated with rate design (i.e., nonproduction costs that are not fully reflected in T&D wheeling rates). For example, this term could include the annual costs of public-policy programs that are assigned to generation and are therefore not reflected in T&D rates.

Implementation of this approach (Eq. 2) is simple. One first estimates the total production costs for each applicable rate class and then estimates, in a consistent fashion, the market price that each class would face. These calculations require only a rudimentary knowledge of the utility's production costs and the wholesale power market. One then estimates

the effects of rate design on lost revenues. The losses associated with rate design will also differ across rate classes because the tariff designs may differ in their allocations of generation vs other costs to different classes. This process requires an understanding of utility accounting and ratemaking but not of wholesale markets or production costs. The results for each of the N rate classes is then summed to obtain the utility's total TC estimate.

The term $(1 - \text{income tax rate})$ shows that any losses experienced by a private firm are offset in part by reduced federal and state income-tax payments. For example, if a utility's combined federal-state income tax rate is 36%, its shareholders will face only 64% of any losses associated with RW. Taxpayers will bear the remainder through lower tax receipts.

We noted above that, in principle, the utility has two options when faced with RW: it can seek to keep the sale and sell power to those customers at market rates, or it can lose the sale and seek to resell some or all of this power to other retail or wholesale customers. At first glance, one might consider this lose-sale option unrealistic. If the utility can sell at wholesale and make money doing so, why could it not keep the RW customers? There are several reasons why both options are, under differing circumstances, viable. First, when the utility loses a sale, the departing customer may have various reasons for purchasing from another entity that go beyond the difference between the utility's embedded-cost price and the bulk-power price of electricity. Second, a utility's corporate policy may limit its willingness to offer customers a discount. Although these two reasons are economically irrational, they nevertheless may occur. Third, when the utility loses a retail sale, it is no longer obligated to meet the year-round, hour-by-hour loads of that customer; it can pick and choose the times during which it will sell this "surplus" power on the spot market. Fourth, transmission losses and congestion might limit a utility's ability to interact with the spot market. The third and fourth reasons relate to the physics of electric-system operations and, if they affect RW customers and the utility differently, could lead to differences between the KS and LS estimates of TCs.

For the LS method, the earnings loss includes three factors. The first is the amount of sales lost to RW multiplied by the difference between the utility's total production cost and its marginal cost. (In the KS formula, this factor depends on the market price of power; in the LS formula, it depends on the utility's marginal costs of serving the departing customers.) The second factor is the change in wholesale sales associated with the loss of retail sales multiplied by the difference between the market price of power and the utility's marginal production cost. This factor is the possible revenue gain to the utility if it can profitably resell some of the lost sales on the wholesale market. In unconstrained competitive markets, the fraction of the RW loss that can be resold is 100%. If market constraints exist, however, the fraction could be less than 100%. Also, the market price in this second term may differ from that in the KS calculation if market inefficiencies exist (e.g., inconsistent treatment of transmission losses and congestion). The third factor is the same as the second factor in the KS formula, losses associated with rate design.

If bulk-power markets are efficient (if the utility and its RW customers face the same transmission constraints, losses, and ancillary-service charges) and if the utility and its RW customers behave in an economically rational fashion, then the KS and LS differences disappear, and the two methods yield the same estimates of TCs.

CRITERIA TO ASSESS ESTIMATION METHODS

How should regulators decide among the various analytical and market approaches discussed above (Table 1)? When faced with conflicting claims about TCs, policymakers need a framework to assess different cost estimates and estimation approaches. We identified eight criteria related to implementation, administrative ease, public availability of data and models, consideration of relevant assets and liabilities, time period considered, market price and value determinations, price and value comparisons, and treatment of market forces (Baxter 1995). In Chapter 5, we describe seven specific methods proposed to estimate TCs and to compare them on each of the eight criteria described here.

IMPLEMENTATION

Implementation describes how valuation is conducted technically and procedurally. Administrative-valuation methods typically are implemented with computer models. Market-valuation methods are implemented by auction, sale, spin-off, or some other market process. Implementation also refers to the need for regulatory proceedings to review estimates, estimation methods, or supporting data.

ADMINISTRATIVE EASE

From the regulator's perspective, administrative ease refers to the relative difficulty of implementing the approach and administering any associated proceedings. "High" administrative ease means the approach is simple and the amount of regulatory involvement in proceedings is comparatively slight.

PUBLICLY AVAILABLE DATA OR MODELS

This category indicates whether the data or models necessary to calculate TCs are publicly available or proprietary. Much of the data needed to estimate TCs is readily available from reports that utilities file with their state regulators and with FERC (especially FERC Form 1). A proprietary model may be available through licensing agreements or other commercial arrangements.

RELEVANT ASSETS AND LIABILITIES

This category describes whether the approach includes those assets and liabilities that many industry analysts agree should be included in TC estimates. The relevant categories, as

discussed above, include utility-owned generation assets; long-term obligations, such as power-purchase contracts and fuel contracts; regulatory assets, such as the phase-in of an expensive power plant; and possibly public-policy programs. Public-policy programs would only be appropriate to include if the utility remains obligated to implement these programs and the costs are not recovered through an appropriate funding mechanism.

TIME PERIOD

The time periods used to estimate TCs differ, depending on the level of aggregation in the analysis. For example, the time periods covered for utility generation and power-purchase contracts often differ depending on the book lives of the generating units and the terms of the contracts. As discussed in Chapter 3, determining an appropriate time period for TC estimation can be difficult. Under some circumstances, annual TC estimates may be positive for a few years and then turn negative (i.e., market value then exceeds book value). Regulators may need to decide whether these future profits should be credited against near-term losses.

MARKET-PRICE (VALUE) DETERMINATION

Estimates of future market prices for bulk-power electricity are made either by using analytic techniques (price estimates—the basis for administrative valuation) or by observing appropriate market indicators. Price estimates can be developed either endogenously or exogenously. Endogenous price estimates are not predetermined assumptions or externally imposed by the analyst, but are instead the result of market simulations or an analysis that explicitly accounts for the economics of plant dispatch in a region. Hence, they are an intermediate result of the analytic method used to calculate TCs. In contrast, exogenous price estimates are derived directly from an assumption or an observation about the cost of different generation options. This estimate is then included as a key input in the TC estimate. See the last section in Chapter 5 for additional discussion of ways to estimate the future market price of electricity.

PRICE (VALUE) COMPARISONS

Transition-cost approaches invariably compare an asset's value under regulation to its market value. This comparison includes three elements: parity, return on equity (ROE), and taxes. Parity refers to whether the regulated price and the market price include comparable elements. Comparing a fully bundled residential retail rate, which includes generation, transmission, distribution, and customer-service costs, to a competitive-market price for generation service is inappropriate if the objective is to estimate TCs caused by the deregulation of generation.

Including any ROE in the valuation is also important because it can have a substantial effect on TC estimates. TC estimates might assume that utility shareholders are held harmless and earn the full authorized ROE on these potentially stranded assets. Alternatively, the analysis

might assume a lower ROE to account for the reduced risk associated with a regulator's guarantee that certain costs will be recovered. Including ROE in the analysis is not necessarily incorrect, although the debate on this issue is still active; see the discussion of government decisions in Chapter 8.

Taxes indicate whether the effects of income taxes are included in the approach, as discussed in Chapter 2. A dollar revenue loss to the utility does not equal a dollar loss to shareholders because the utility does not have to pay federal, state, and local income taxes on the lost revenue.

More generally, development and comparison of TC estimates require close attention to certain key assumptions and their internal consistency. As discussed above, these assumptions concern the return *of* as well as the return *on* equity, the time period to be used in analyzing TCs, and consistency in the determination of the market and regulated prices for individual assets and liabilities. Consistency refers to analysis at the same level in the T&D system, inclusion of generation services only, and consideration of the load shape for the customer classes in question.

MARKET FORCES

Utility actions and the actions of the larger bulk-power and retail-power markets will affect TCs. For example, high-cost utilities will likely respond to increased competition by lowering costs and improving the performance of their generating units (e.g., by lowering heat rates and reducing forced outage rates). Many utilities will pursue previously protected markets to increase sales. Such efforts will affect the TCs that utilities ultimately face. Similarly, the wider marketplace will also respond to increased competition. Over time, electricity prices will change as more and different consumers and suppliers participate in competitive electricity markets. These changes should lead to short-run and long-run changes in both demand and supply. Should current capacity surpluses tighten, prices should rise, thus stimulating development of new supplies. The interaction of demand and supply over time will, in turn, determine future market prices, which directly affect TCs. Rose (1996) uses the term "dynamic efficiency" to describe the long-term effects of these market forces. Over time, supply costs for utilities and other generators will approach the industry's marginal costs of generation.

SPECIFIC APPROACHES TO ESTIMATING TRANSITION COSTS

Here we describe seven estimation approaches, each of which represents one of the basic approaches discussed in Chapter 3 (Baxter 1995). One approach is a proposal for actual cost recovery (FERC), four focus on national TC estimates or industry-wide issues (Moody's Investors Service, Resource Data International, R. J. Rudden Associates, and Sant and Naill), and two provide detailed utility-specific estimates (Southern California Edison and the Texas PUC). The FERC proposal (addressing wholesale TCs) is included because it has attracted widespread national attention. A unique feature of Moody's approach is the use of transparent techniques to estimate market prices for capacity and energy that are consistent with economic principles and market realities. The RDI and Rudden approaches are examples of BU methods that feature market prices estimated with market simulations. Sant and Naill is a prominent example of a market-valuation approach. Table 2 assesses each of these seven approaches relative to the eight criteria discussed in the previous chapter. The final section discusses alternative analytical approaches to estimating future market prices for electricity, a critical determinant of TC amounts.

FEDERAL ENERGY REGULATORY COMMISSION

FERC's (1996a) approach addresses TCs arising from its implementation of non-discriminatory transmission access by public utilities. FERC favors a TD, administrative-valuation approach. The approach is consistent with FERC's desire to directly assign TCs to the departing wholesale customer. The annual revenue loss to the utility is defined as the difference between the utility's expected revenue stream from the departing customer (less the utility's expected transmission revenue under its new wholesale transmission tariff) and the market value of the capacity and energy "released" by the customer's departure. The departing customer's TC obligation is the product of the utility's annual revenue loss and the number of years the utility could have reasonably expected to serve that customer, expressed on an NPV basis.

FERC calls its method a revenues-lost approach. It requires the utility requesting cost recovery to use the following formula for stranded cost obligation (SCO):

$$SCO = (RSE - CMVE) \times L .$$

Table 2. Assessing different transition-cost-estimation approaches^a

Assessment criteria		FERC	Moody's	RDI	R. J. Rudden	Texas PUC	SCE	Sant & Naill
Implementation		Utility	Computer model	Computer model	Computer model	Utility	Utility	Auction
Administrative ease		High	Medium	Low	Low	High	Medium	High
Publicly available data and models		Yes	Public data, replicable model	Public data, proprietary model	Public data, proprietary model	Yes	Yes	Not needed
Relevant assets and liabilities		Yes	No	Yes	Yes	Yes	Yes	No
24	Time period	Reasonable expectation to serve	10 years	10 years	User specified	Life of assets	One year (1998)	Life of assets
Market-price determination	Estimate	Option 1	Endogenous	Endogenous	Endogenous	Exogenous	Exogenous	No
	Market	Option 2	No	No	No	No	No	Yes
Price comparisons	Parity	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	ROE	Yes	No	Yes	Yes	Yes	Yes	NA
	Taxes	No	No	No	No	No	?	NA
Market forces	Utility	No	No	Yes ST	Yes ST	No	No	Yes
	Market	Yes ST	Yes ST	Yes ST	Yes ST	No	No	Yes

^aAbbreviations are: ST = short term, NA = not applicable, ? = undecided or not possible to determine.

The revenue stream estimate (RSE) is the average annual revenue from the departing wholesale-generation customer minus the transmission revenue that the utility would have received from that customer. This average revenue is computed on the basis of the three years prior to the customer's departure. Presumably, the 3-year average is intended to provide a number that is robust and insensitive to short-term fluctuations, such as adverse hydro conditions or extreme weather.

The competitive market value estimate (CMVE) over period L can be determined in one of two ways at the option of the customer. Under Option 1, the utility estimates the market price using a method of its choice. Under Option 2, the utility estimates market price using the average annual cost as reflected in the departing customer's agreement with its new supplier(s).

The length of obligation (L) is the time during which the utility could have reasonably expected to continue to serve the departing customer.

FERC capped the quantity ($RSE - CMVE$) to be no greater than the annual contribution to fixed power supply costs that would have been made by the departing customer. (Presumably, these fixed costs include both avoidable O&M and capital costs.) This cap is meant to ensure that a utility does not continue to operate generating units whose avoidable costs exceed the market price of power; in such cases, it would be cheaper for the utility to shut down these plants and thereby avoid the unit's fixed O&M costs. FERC's use of historical data to calculate RSE may lead to an overestimate of TCs because these data cannot capture the likely decline in generator-unit capital costs over time or the possibility that the generator will be shut down because it is no longer economical to operate (i.e., its revenues are not enough to recover its avoidable fixed costs).

The utility is charged with developing the TC estimate, but the departing customer can decide whether to rely on the utility's estimate of market price (Option 1) or on the price revealed by the deal the customer struck in the marketplace (Option 2). FERC's approach will be relatively easy to administer, although disputes between parties will ultimately be resolved by FERC. To encourage parties to settle TC claims without litigation, FERC requires the utility to mitigate TCs by subtracting the market value of the departing customer's former purchase from the customer's TC obligation. In addition, if the customer believes the utility's market price estimate is low, FERC permits the customer to market or broker the released energy and capacity and keep the resulting revenue. This option should discourage utilities from boosting the SCO number by estimating a CMVE that is too low.

Should the customer elect to have the utility develop market-price estimates, the methods and assumptions used by the utility will be available to the affected customer and, in the case of an unresolved dispute between the utility and customer, will be publicly available in a FERC proceeding. Assuming that the customer's present wholesale rate includes all the utility's costs of providing service, the estimation approach includes all relevant assets and liabilities. FERC does not specify a specific time period to estimate TCs. Instead, the calculation will reflect the

annual loss for the number of years that the utility could reasonably expect to continue service to the customer.

Because the utility is free to use any method to estimate market prices under Option 1, it is not possible to comment on how those prices will be determined. The price obtained from Option 2 will reflect a market determination. Once adjusted for transmission revenue, the comparison of regulated and market prices should be appropriate. The regulated price may include a component for ROE, but the effects of taxes are not included. The FERC approach is a one-time, ex ante estimate; thus, no assumptions are made about the effects of either continuing regulation or market forces on future utility costs. The TC estimate should include the short-term effects of market forces, as reflected in the market-price estimate, whether made by the utility or based on the customer's new supply contract. It is not clear whether the effects of long-term market forces are reflected; this will depend on the method used to estimate market prices.

FERC's ex ante approach requires the use of assumptions, especially about the market value of power, with no subsequent reconciliation. FERC believes that the certainty this approach provides to both utilities and departing customers outweighs the gains associated with the improved accuracy of periodic true ups.

MOODY'S INVESTORS SERVICE

Moody's (Fremont et al. 1995; Hackett, Cohen, and Abbott 1996) uses an administrative, ex ante approach to develop national estimates of TCs for the major investor-owned utilities. The approach uses plant-specific data to estimate market prices and TCs for each of the North American Electric Reliability Council regions. Moody's approach is unique in two respects: (1) the market price estimates for capacity and energy are derived from transparently constructed supply curves, and (2) the approach is motivated by the concept of a "break-even price" for capacity.

Moody's estimates TCs as a utility's total capacity multiplied by the difference between a utility's break-even price for capacity (adjusted for purchased power and regulatory assets as necessary) and the regional market price of capacity. Moody's assumes that a utility unable to recover all its fixed production costs through energy sales will have to charge for capacity. The break-even price is the amount a utility must charge for capacity to ensure recovery of all fixed production costs, assuming the sale of 100% of its capacity. Any margins the utility earns through energy sales are applied to fixed costs. The greater these margins, the lower the capacity charge need be for the utility to recover its fixed costs, or to "break even."

A key feature of Moody's approach is the estimation of market prices for capacity and energy. Moody's derives both estimates by constructing supply curves for capacity and energy in each region and then estimating the average demand for these two services. Moody's defines the market price for capacity as the marginal cost of the most expensive unit needed to satisfy

forecast demand (including a reserve margin) in each region. Moody's defines the market price for energy as the variable production cost of the most expensive plant producing energy at the average level of demand in a region. Individual plants form points on the supply curve in order of increasing cost. Changes in the average demand for energy will result in different market prices for energy, different break-even prices, and different TC estimates.

Moody's approach represents a middle ground between the simple TD approaches and the more complex BU methods. Like other BU approaches, Moody's attempts to reflect the effects of regional supply and demand conditions on market prices, but does so using a transparent approach. The market-price estimates embody basic utility-economics principles and market realities—individual plants are dispatched in order of increasing variable costs, and the value of capacity depends on existing and anticipated capacity/demand balances in each region. While transparent, this approach is more difficult to implement than one that simply assumes a market price based on recent observations in the wholesale market or the estimated costs of supply.

A reasonable question is whether Moody's assumption, that a future electricity market will value both energy and capacity, is tenable. More importantly, however, the robustness of this assumption is not strongly linked to the robustness of the resulting estimates. Moody's is attempting to measure the most relevant costs affected by the deregulation of generation: fixed production, power purchases, and regulatory assets. The distinguishing feature of this approach is the focus on cost recovery through both capacity and energy sales rather than solely from energy sales, as with other administrative-valuation methods. The approach's basic formulation focuses on estimating a utility's potential unrecovered fixed costs when competitive markets set prices for generation services. Virtually all the administrative-valuation methods reviewed for this study use this approach.

A possible shortcoming of Moody's approach is the use of averages to simplify the analysis. Use of average demand to estimate an average market price for energy is a simplification of operating conditions. When demand exceeds the average demand, plants with variable production costs above the average market price can operate at a profit. Conversely, when demand falls below the average, plants with variable production costs below the average market price can operate at a loss. Only if hourly demand is distributed symmetrically around this average will the differences cancel.

Moody's does not include fuel-purchase contracts in its TC estimates. In addition, the price comparisons used to estimate TCs do not include ROE or tax effects, but the break-even and capacity prices are comparably constructed. Finally, Moody's makes no assumptions about the effects market forces may have on future utility costs or how alternate suppliers and consumers might respond to changing market conditions over time.

RESOURCE DATA INTERNATIONAL

The RDI (1994; 1996) approach is an example of a BU, ex ante administrative-valuation method. The Inter-Regional Electric Market Model (IREMM) is at the heart of the RDI approach (Coste and Adams 1994; Coste 1996). IREMM has two primary features. First, the model has a production-cost feature that simulates utility operation, including unit dispatching, maintenance scheduling, and cost accounting. The production-cost feature operates at the generator-unit level for all investor-owned utilities and the largest municipal utilities in the continental United States; the production-cost analysis includes both utility and nonutility generation. Second, IREMM estimates market prices for each utility and identifies the energy transactions that result from the interaction of supply and demand for energy in the wholesale market. IREMM simulates the operation of a competitive wholesale market in which each utility attempts to maximize its profits on sales and its savings on purchases. The objective of IREMM's wholesale-market simulation is to maximize the economic benefits of these profits and savings over all utilities, subject to the constraints of supply, demand, and the regional transmission system.

The RDI method has the strengths characteristic of a BU approach. RDI provides a detail-rich analysis based on the operating performance and economic attributes of individual generating units. As a result, the method is able to link TCs to specific generating assets. The RDI method also relies on an endogenous estimate for market price rather than an exogenous assumption. These prices are derived from a market simulation of essentially the entire interconnected bulk-power electric system. In addition, the market-price estimates begin to reflect the time-varying nature of electricity costs; market prices are estimated monthly for three time periods: on-peak, mid-peak, and off-peak.

As with the TD approaches, the strengths of a detailed BU analysis are accompanied by certain weaknesses. The simulation requires a sophisticated modeling tool. IREMM is not transparent and may be difficult for regulators to apply in the context of public proceedings. In addition, the details of the simulation require numerous assumptions about unit operating performance and costs, including heat rates, O&M costs, and maintenance schedules, as well as assumptions about future demand growth and supply requirements. The amount of detailed data needed to implement the method suggests increased opportunities for disagreements and attendant litigation about the appropriate assumptions. Use of such a model for regulatory determinations of TCs will impose difficulties in data development and maintenance and also in model implementation.

The assessment of utility operating revenues and generation cost obligations appears to be based on comparable price or cost elements. Thus, the market price for generation is a wholesale price net of transmission charges, and the cost of utility generation includes both fixed and variable costs. The fixed-cost component for utility generation includes an explicit ROE. The RDI approach, like all those reviewed in detail, does not consider the effects of income taxes on TCs. IREMM appears to partially reflect the effects of short-term markets.

Utilities respond to market-price signals to determine whether they are buyers or sellers on the wholesale market. This simulated market includes the effects of indirect transactions (transactions between two systems separated by intervening companies through which the power must be wheeled). It does not appear, however, that potential long-term market forces are reflected. Future demand and supply are taken as exogenous assumptions as are a utility's future operating performance and costs. Thus, the RDI approach does not consider how future demand and supply might respond to changing prices and costs as a result of a more competitive environment.

R. J. RUDDEN ASSOCIATES

The R. J. Rudden Associates (1994) approach is a BU, ex ante, administrative-valuation method. At the center of this approach is a proprietary model, the Electric Power Market Model (Wile 1996). It includes all utility and nonutility generating units in the U.S. and divides the country into 26 regions corresponding to the North American Electric Reliability Council subregions and some further regional disaggregation.

The model accounts for the operating characteristics and costs, including nonfuel O&M, for each existing unit and new generation option and, for nuclear plants, capital additions as well as the capital costs for new generating alternatives. Demands are defined by season and time of day. Over a specified planning period, the model minimizes the present value of the overall costs of meeting the projected regional demands, which is the outcome of a competitive power market. In so doing, the model determines the prices for energy *and* capacity that would emerge in competitive markets.

The model uses a production-costing algorithm to dispatch all generating units, taking into account forced outage rates, availability rates, and overall maintenance requirements in determining the lowest cost of meeting demands. There are several key features of the model. It projects the economically optimal mix and timing of new capacity additions on a regional basis. It schedules planned maintenance for all units. The model determines the output for each generating unit. It determines which existing generating units are uneconomical and whether they should be placed in cold storage or retired. The model explicitly recognizes transmission links among the regions and the limits on power flows across the links. Power will flow from low- to high-cost regions until differences in the regional prices by season and time of day are reduced to reflect only losses and wheeling charges or until transmission limits are reached.

The model projects both competitive energy and capacity prices. The energy component of competitive prices is the variable (fuel plus variable nonfuel O&M) cost of the unit that would be used to meet the next increment of demand.

Capacity prices depend on the supply and demand balance and the mix of generating equipment in a region. Some systems have excess capacity (capacity above that necessary to maintain adequate reserves). When new capacity cannot economically displace existing

facilities, the capacity price is the fixed nonfuel O&M cost for the least costly unit available to meet the next increment of peak demand. If, however, new plants can economically displace existing facilities, the price for capacity will be the fixed nonfuel O&M cost for the least costly existing unit that would be used to meet the next increment of demand in the absence of new additions less the energy savings. (This energy-saving term is the difference in variable costs between the unit being displaced and the new, lower-cost unit.)

For some systems, new capacity is necessary to meet reliability requirements. If the new capacity is a combustion turbine and is used only for meeting reliability requirements and does not displace energy from existing facilities, the capacity price is its annual capital charge plus its fixed O&M costs. If, however, new capacity is needed to meet reliability requirements and displaces energy from existing, less efficient facilities as well, the capacity price will be the annual capital charge plus fixed O&M costs of a new combustion turbine less the energy savings. The model determines the optimal mix and timing of new capacity additions, taking into account the savings from displacing older, less efficient facilities.

TCs for a unit are the difference between the present value of the net revenues it generates and its unamortized investment. A unit's annual net revenues are the difference between its (1) revenues from the sale of capacity and energy plus, for fossil plants, the value of sulfur dioxide emission allowances and (2) incremental costs (i.e., fuel, O&M costs, and future capital additions). A unit's revenues will be determined by its capacity, capacity factor, and the competitive prices for capacity and energy.

TEXAS PUBLIC UTILITY COMMISSION

The Texas PUC (1996 and 1997) sponsored several workshops with utilities and other interested parties to define the key issues associated with TCs. The Commission staff developed a BU, ex ante, administrative-valuation method. The PUC's calculations and results were meant primarily for use in a report to the Texas Legislature, not to determine how much money the utilities would be entitled to recover. Two features make the Texas PUC approach especially interesting. First, the PUC staff developed a spreadsheet that each utility used to report its results to the commission. Use of a common spreadsheet ensured consistency in reporting format and made it simpler to compare results across cases and utilities. Second, the commission specified scenarios and market prices that all the utilities were required to use. Thus, certain key assumptions were determined beforehand.

The commission's estimates of market price included both short- and long-term considerations. In the short term, the fuel plus variable O&M costs for a gas-steam unit determined the average marginal cost of electricity. In the long term, the full cost (capital, fuel, and O&M) of a combined-cycle gas-fired unit determined the marginal cost. Thus, estimates of future gas prices were crucial inputs to this process. The short term was defined as the number of years during which existing capacity would be sufficient to meet demand. The long term begins when new capacity needs to be constructed, assumed to be 2001. Thus, market

prices are assumed to increase over time, starting at the short-run marginal (fuel plus variable O&M) cost and increasing to the embedded (fixed plus variable) costs of a combined-cycle unit. The three projections of market price (i.e., low, base, and high) each consist of short- and long-term marginal-cost projections that differ in their assumptions about future natural gas prices and the cost of building a new combined-cycle unit.

The commission defined six scenarios that each utility was required to run in developing estimates of TCs, as shown in Table 3. These scenarios differ in the date that different retail customer classes gain access to competitive electricity markets. Scenario 1 calls for immediate access for all customer classes. At the other end of the spectrum, Scenario 4 allows for a much more deliberate phasing-in of retail access.

Table 3. Six scenarios defined by the Texas Public Utility Commission

	Scenario					
	1	2	3	4	5	6
1998	All		Industrial	Industrial	½ Industrial	Residential
1999					½ Industrial	
2000		All	Commercial		½ Commercial	Commercial/ Industrial
2001					½ Commercial	
2002			Residential	Commercial	½ Residential	
2003					½ Residential	
2004						
2005						
2006				Residential		

The commission also specified the discount rate that utilities were to use in calculating the NPV of their TCs (8.5% after tax for the investor-owned utilities and 7.5% for municipal, cooperative, and river-authority utilities). The commission also specified the rate of return to use in these calculations (10% for investor-owned utilities and 7.5% for the other utilities). Finally, the commission specified a forecast period as the remaining life of the longest-lived generation asset in rate base, which could extend the analysis through 2033.

The basic formula used by the commission to determine TCs is:

$$TC = NPV[FC - (MP - AVC) \times MWh] ,$$

where FC is the fixed costs of current assets, MP is the market price of electricity, AVC is the utility's average variable cost of electricity, and MWh is electricity sales at market price. This calculation is performed for each of a utility's generating units and power-purchase contracts. If AVC is greater than MP, the plant will not be run, and TCs will equal fixed costs; in such circumstances, the unit should probably be retired.*

The Texas method is a BU approach because it requires the utilities to provide information on the costs and revenues associated with each technology and fuel type. The utilities needed to calculate the costs and revenues for each generating unit and power-purchase contract to comply with this Commission requirement. The Commission did not, however, specify how the utilities were to calculate these dollar amounts (i.e., which production costing and financial models to use).

SOUTHERN CALIFORNIA EDISON

In response to the California PUC's (1995) major restructuring order, Southern California Edison (SCE 1996b) filed a 2-in.-thick document that includes 13 reports. The number and content of these reports illustrate the complexity and range of issues encountered when a utility seeks TC recovery. These reports deal with: TC policy; TC collection; 1998 market price used to determine TCs; TCs arising from qualifying-facility obligations (QFs, authorized by the 1978 Public Utility Regulatory Policies Act); TCs for nuclear generation; TCs for fossil generation; fuel and fuel transportation contract obligations; plant-related sunk costs and rate base for fossil generation; TCs for hydro generation; TCs arising from interutility contracts; TCs for regulatory assets, obligations, and balancing accounts; early retirement, severance, and retraining TCs; and TC ratemaking.

SCE estimates its 1998 transition-cost revenue requirements (the amount it would like to collect from retail customers through a competition transition charge) at \$3.28 billion. Of this total, 50% is from long-term contracts with QFs; 33% is from SCE's San Onofree and Palo Verde nuclear units; 14% is from SCE's fossil units and long-term fuel and fuel-transportation contracts; and the remaining 3% is from interutility contracts, regulatory assets, hydro facilities, and employee costs.

SCE suggested a very simple method to estimate the market price of power, based on the price of natural gas and a factor that varies from month to month. The estimated market price in 1998 is 2.34¢/kWh. SCE used this price to estimate the revenues it would receive from each of its generating assets. For example, SCE estimates it will pay QFs \$2,300 million in

*Because this method bases market prices on the cost of running a combined-cycle unit, it does not account for the time-varying nature of prices. That is, combined-cycle units will be on the margin for only some of the 8760 hours of the year. At some times, less expensive plants will set the price; and at other times, more expensive plants will set the price.

1998 and that the market value of this power will be \$670 million, yielding a TC estimate of \$1,630 million.

Although SCE's method to estimate the market price of power is simple, its use of a very detailed BU accounting approach is complicated. To illustrate, Table 4 shows the cost categories that SCE (1996a) used to calculate the sunk costs associated with each of its non-nuclear generating assets. Sunk costs were defined as "the original cost recorded in the company's books for a particular asset less any accumulated depreciation and adjusted for deferred taxes, and any other asset or liability account which relates to the asset [which includes all plant-related regulatory assets and liabilities, decommissioning liability, and deferred tax assets and liabilities]." Of the \$2.1 billion total as of December 1995, \$3.6 billion represents plant in service, \$2.1 billion represents depreciation and amortization, and \$0.6 billion represents plant-related items (i.e., $\$2.1 = \$3.6 - \$2.1 + \0.6).

Although much of the detail in SCE's approach is of an accounting nature, that does not preclude the opportunity for debate over which costs belong where. Pacific Gas & Electric (1996), in its comparable filing with the California PUC, discussed some transmission facilities that it felt should more properly be classified as generation assets:

Gen-ties are those transmission lines and related equipment that are used solely to deliver generated electricity from the power plants to the transmission grid. Gen-ties consist of land rights, insulators, conductors, switches, poles, and towers that are used to transport power from a generator to the transmission grid. In some instances, gen-ties cover only a very short distance; in others, they can cover thirty miles or more. PG&E has associated the costs of these lines with the generation function because ... these facilities are necessary to deliver generated electricity to the transmission system.

These examples illustrate the complications that can occur in application of BU methods to calculating TCs. On the other hand, these examples illustrate the rich details that these methods provide.

SANT AND NAILL

Sant and Naill (1994) propose a market-valuation approach designed to provide a guaranteed market for the electricity generated by divested assets. Under their scheme, the generating assets would be divested through a public offering or through a spin-off. Any auction or sale would be conducted by the utility and could include individual assets or packages of assets. Utility-affiliated generating companies could participate in the auction if the parent company had spun off the affiliate so that no association existed between the affiliate and the parent company.

Table 4. Cost categories that Southern California Edison used to calculate sunk costs for nonnuclear generation assets. (Net book value is A minus B plus C.)

A. Plant in Service

1. Generation
2. Generation-related transmission
 - Step-up transformers
 - Other related equipment (feeders, circuit breakers)
3. General
 - Site specific (furniture, computers, warehouse buildings)
 - Non-site specific
4. Land
5. Intangibles (radio frequencies, capitalized software)

B. Depreciation and Amortization Reserves

1. Generation
2. Generation-related transmission
 - Step-up transformers
 - Other related equipment
3. General
 - Site specific
 - Non-site specific
4. Land
5. Intangibles

C. Plant-Related Items

1. Construction work in progress
 - Construction work in progress
 - Retirement work in progress
 2. Inventories
 - Materials and supplies
 - Fuel-oil inventory
 - Gas inventory
 - Coal inventory
 3. Taxes
 - Accumulated deferred taxes related to accelerated depreciation
 - Accumulated deferred investment tax credits
 - Deferred tax assets (flow-through)
 - Deferred tax-uniform capitalization
 - Accumulated deferred fuel oil
 4. Environmental compliance
 5. Decommissioning
-

Sant and Naill propose two important conditions on the asset sale. First, the selling utility would be guaranteed at least book value for the asset. To encourage prospective buyers to bid at or above this level, they would be offered a fixed-price contract from the utility for the electricity generated over the rest of the asset's economic life. The fixed-price contract would set a price at which the utility would purchase the unit's output, which would include the remaining undepreciated capital costs for the asset, including an ROE, fuel costs, and nonfuel O&M costs. Based on these costs, the utility would calculate a rate schedule that would include a 5% reduction in the overall rate needed to recover the above costs, representing potential cost savings from reducing capital costs, fuel costs, O&M costs, or from increasing plant availability. The state PUC would guarantee that the selling utility would be able to charge its customers for electricity at the contract price. Bidders would then bid to acquire the generating asset and the contract.

At the end of the contract period, asset owners would negotiate new contracts at competitive market prices or sell electricity on the spot market. Thus, the Sant and Naill approach encourages utility divestiture, provides asset purchasers with a long-term guaranteed market (and the prospects for higher profits through cost savings), and offers ratepayers the guarantee of at least a modest reduction in their current rates. Certain questions, however, such as which entity bears the risk of plant outages or changes in electricity demand, are not addressed. These questions would have to be resolved before the fixed-price contract was completed.

Because the utility is conducting the auction and calculating the terms of the long-term power purchase, the administrative obligations of regulators are limited to oversight and review. The auction and fixed-price contract effectively transfer the utilities' TCs to the utilities' retail customers (less a 5% rate reduction). The auction provides a measure of market value at the time of the sale only if the highest bid is above the asset's book value. This constraint on the minimum sale price, which is necessary to transfer the associated TCs, creates an asymmetrical auction in which market values will only be revealed when market values exceed book values. Assets with these latter characteristics do not contribute to TCs. A general problem with the auction approach to TCs is that the assets contributing to the problem almost by definition have the least desirable market characteristics.

Sant and Naill recognize this problem and suggest that one solution would be to package desirable and less desirable plants (or portions of plants). For packaged assets, the utility would presumably be guaranteed recovery of their total book values. Sant and Naill do not suggest, however, what would make such a guarantee possible or who would enforce such a guarantee. The proposal also captures several aspects of market forces. The new asset owners would have incentives to reduce generating costs in both the short and long terms. Over the long term, all asset owners would be exposed to the market forces that would encourage competitive long-run marginal generation costs. These competitive forces would be muted in the short run, however, because the proposal delays the onset of full retail competition until the guaranteed contracts expire. This delay could differ, perhaps greatly, among utilities because it would be tied to the

depreciation schedules of individual assets. Some depreciation schedules may extend beyond any contract life acceptable to asset purchasers or regulators.

In addition, Sant and Naill recognize that a nationwide sale of generation would be difficult to implement and might depress bid prices, particularly if conducted before restructured markets began to operate. As a result, they recommend conducting auctions on a state-by-state basis over ten years or more. But because full retail competition would be delayed until the contracts awarded as a condition of the auction expire, markets would not see retail competition for many years. This delay would not be a problem for states where retail competition is not a primary objective.

Nuclear-plant auctions would require additional features. For example, Sant and Naill suggest that nuclear plant buyers may require federal insurance protection to guarantee waste disposal and decommissioning costs. Unlike other plants, the selling utility might have to bid on its own nuclear units. In the absence of other bids, the plants would remain with the utility. Alternatively, the utility could sell the output from the plants, rather than the plants themselves, under long-term contracts to electricity distributors or individual customers. Even with these provisions, the existence of a market for nuclear units is highly uncertain. Indeed, Kahn (1994) argues that "The costs associated with the back end of the nuclear fuel cycle and the decommissioning of reactors are fundamentally unknown. ... the risks associated with nuclear power are difficult, if not impossible, to price in the private marketplace." As a consequence, Kahn believes that nationalization of the nuclear-power sector is both necessary and unavoidable.

Although most market-valuation approaches focus on generating assets, the same approaches could be applied to long-term fuel and power-purchase contracts. For example, utilities could auction off or otherwise sell their fuel and power-purchase contracts. By definition, these approaches do not apply to regulatory assets, which have zero market value.

ESTIMATING THE FUTURE MARKET PRICE OF ELECTRICITY

As discussed in Chapter 4, the market price of electricity at the generator busbar (i.e., the bulk-power price without the costs of T&D) is a critical determinant of the amount of TCs a utility faces. The different methods discussed earlier in this chapter use a variety of approaches to develop these estimates. Because these estimates are so important, we present additional details on how they are developed.

The TD methods typically use very simple assumptions about the future price of generation output. For example, Duff & Phelps (1996) assumed that "70% of sales will be into the firm wholesale and retail markets at 3¢/kWh, with the remaining 30% of sales at 2¢/kWh nonfirm, spot prices." This assumed price of 2.7¢/kWh was applied nationwide in calculating the transition costs that each utility faces.

The Texas PUC (1997) developed an intermediate approach. The PUC's estimates of market price include both short- and long-term considerations. In the short term, the fuel plus variable O&M costs for a gas-steam unit determine the average marginal cost of electricity. In the long term, the full cost of a combined-cycle gas-fired unit determines the marginal cost. Market prices are assumed to increase over time, starting at the short-run marginal (fuel plus variable O&M) cost and increasing to the embedded (fixed plus variable) costs of a combined-cycle unit. With this approach, one can develop alternative projections of market price based on different assumptions about future natural gas prices, surplus capacity in a region, and the cost of building a new combined-cycle unit.

Finally, some estimates of market prices are derived from detailed modeling of the operations of individual generating units and regional transmission networks (e.g., the RDI and Rudden approaches). IREMM is a leading example of this approach (Coste 1996). Rather than assuming a market price or assuming the type of generator that will be on the margin (and therefore will define the market price), IREMM calculates market-clearing prices based on the interaction of supply and demand for electricity. The model simulates the operation of individual generating units for 36 time periods a year (12 months for on-, mid-, and off-peak hours). Generators, both utility owned and independent power producers, are grouped into more than 100 market regions (including several in Canada and Mexico). The power flows among these regions are based on a DC load-flow model, which accounts for transmission constraints among these market regions.

The model first dispatches the generating units to meet each individual market area's loads. Once these loads are served, the amounts of surplus energy available for sale and the amounts of economically displaceable energy are calculated for various price levels. Based on these "surplus" supply and demand curves, the model then calculates the flows of energy between any two market areas, limited by any transmission constraints and costs (wheeling charges). Equilibrium occurs when additional profitable trades cannot occur among regions. The net result is a set of market-clearing prices for each region. In addition, the model calculates the output from each generating unit and, based on the time-varying market prices, the total and net revenues associated with each unit. Thus, IREMM's calculations are based on endogenous and simultaneous determinations of market prices and bulk-power transactions. (Simpler methods, on the other hand, assume that the market is infinite at the assumed market price. In other words, the amounts of electricity that can be bought and sold are assumed to be unbounded. In IREMM, however, the amounts of electricity traded and the prices interact.)

One important strength of the detailed models is their ability to consistently analyze different scenarios. For example, Coste used IREMM to analyze the effects on market price of changes in fossil-fuel prices, nuclear-unit availability, no new construction of generating units, transmission tariffs (wheeling charges), and load growth. As shown in Fig. 6, changing these assumptions can affect market-price estimates by about $\pm 20\%$. For example, if nuclear output is 10% above its base-case value, prices are 4% lower.

A key disadvantage of these detailed models is their complexity. These models require an enormous amount of input data and assumptions. In addition, the complexity of model calculations can make it difficult to interpret model results. Thus, as with the TD and BU methods discussed in the report, one must make tradeoffs in selecting a suitable approach to calculating the future market prices of power.

Fig. 6. Estimates of the on-peak market prices of electricity for the year 2000 for one utility service area under different assumptions.

FACTORS THAT AFFECT TRANSITION-COST ESTIMATES

As discussed in Chapter 3, the methods used to determine TCs can affect the amounts estimated. And the preceding chapter showed that there are substantial differences among methods. This chapter demonstrates the effects of assumptions on TC estimates.

Table 5 shows some of the many factors that affect utility operations, costs, and therefore TCs. We divided these factors into three categories. Regulatory factors are those that the state regulator can influence, wholesale-market factors affect the interactions between the utility and wholesale power markets, and accounting factors affect the utility's income statement and balance sheet but not its interactions with wholesale markets.

We used the Oak Ridge Financial Model to conduct all the analyses presented in this and the following chapter (Hadley 1996). The sensitivity results presented here and the mitigation results presented in Chapter 7 are valid only for this hypothetical utility. But the results are qualitatively applicable to a broad range of utilities that face substantial TC problems. The base case used here differs from the one presented in Baxter, Hadley, and Hirst (1996) to ensure consistency between the results presented in Chapters 6 and 7.

First, we created a base-case utility, using historical data from the Energy Information Administration. We did not create a utility that is typical of U.S. investor-owned utilities; rather, we created a hypothetical utility with a substantial TC problem. For the reference case, we simulated the finances, operation, and rates of this utility from 1995 through 2005, assuming no RW and traditional cost-of-service regulation.

Then, we hypothesized a pattern of RW, starting at zero in 1995, increasing linearly to 42% of the retail load in the year 2000, and remaining constant from 2000 through 2005. We assumed that the state regulator would permit recovery of TCs for the 10-year period from 1996 through 2005. To assess the sensitivity of various factors on TCs, we changed the values of individual variables in both the reference and RW cases.

The utility's earnings loss amounts to 45% of shareholder equity (Fig. 7). If remaining retail customers bear all the transition costs associated with RW, their rates increase relative to the nonwheeling case by a maximum of 24% in the year 2000. For additional details on the TCs that the utility faces, as well as the losses experienced by remaining retail customers if the utility's earnings are held constant, see Hirst, Hadley, and Baxter (1996b); see also the Appendix.

Table 5. Factors affecting the amount of transition costs a utility faces

Factor	Wholesale market	Accounting
Generation Assets		
Capital costs (initial cost, depreciation, taxes, etc.)		✓
Fixed production operations and maintenance		✓
Variable production operations and maintenance	✓	
Forced and planned outage rates	✓	
Liabilities		
Power-purchase fixed costs		✓
Power-purchase variable costs	✓	
Deferred income taxes		✓
Regulatory assets		✓
Annual nonfuel expenses		
Public-policy programs that are expensed		✓
Other costs (e.g., administrative and general expenses) not in wheeling rates		✓
Other factors		
Load growth by customer class	✓	
Customer-class load factors	✓	
Customer-class loss factors	✓	
Inflation rate		✓
Tax rates (e.g., income, property, and revenue)		✓
Wholesale-power prices	✓	
Difference between wholesale purchase and sale prices	✓	
Number of customers that choose retail wheeling	✓	
Transmission capacity for wholesale transactions	✓	
Ancillary-service costs		✓
Regulatory factors		
Year retail wheeling begins	✓	
Number of years for which TC recovery is allowed		✓
Type and frequency of rate cases		✓
Authorized return on equity		✓

Fig. 7. Effects of retail wheeling on retail electricity prices or annual earnings losses to utility shareholders.

REGULATORY FACTORS

PUCs have substantial influence over the timing and extent of RW and therefore over the amount of TCs that a utility or its customers might face. These factors include the year that RW begins, the number of years for which TCs are calculated, and the type and frequency of rate cases.

For a variety of reasons, many states have delayed the onset of RW. One motivation for such delays is the decline in TCs that the passage of time provides. The natural decline in fixed production costs is a powerful incentive to slow implementation of RW. For the base case, fixed production costs decline by 50% between 1995 and 2005; about half of this decline is caused by depreciation, with the remainder caused by inflation and load growth. (During this 10-year period, the utility builds no new generating units. As a consequence, its reserve margin declines from 34% in 1995 to 6% in 2005.) Each one-year delay reduces the utility's TCs by about 18%, assuming that the utility is allowed to recover costs for a full 10-year period (Fig. 8). A 3-year delay from 1996 to 1999 cuts the amount of TCs almost in half. Of course, these results assume that state regulators and utilities can prevent retail customers from finding other, lower-cost sources of electricity (e.g., through cogeneration).

Fig. 8. Transition costs as a function of the year that retail wheeling begins relative to the loss that would occur if retail wheeling began in 1996.

How much money might the utility lose if it is allowed to recover costs for a period less than the full 10-year period considered here (1996 through 2005)? Both because of the time value of money and the assumed increase in wholesale prices after 2000, the NPV of the amounts to be recovered in the later years is much less than the NPV of the amounts to be recovered in the early years. For example, reducing the recovery period from 10 to 8 years permits the utility to recover almost 90% of the total 10-year TC amount. Only if the recovery period is five or fewer years does the utility face substantial losses (e.g., only 40% of the total 10-year amount if recovery ends in 2000).

WHOLESALE-MARKET FACTORS

The interactions between a utility's generating resources (both its own generating units and its power-purchase contracts) and the wholesale market affect the amount of TCs. As shown in Eq. 2, TCs depend on the difference between a utility's production costs and the market price. And a utility's production costs depend on market conditions (i.e., the utility's opportunities to buy and sell power on the wholesale market). TC analyses must treat consistently the effects of changes in regional load growth, fuel prices, and other factors that might affect bulk-power markets on both utilities and other suppliers. Here we examine the influence of wholesale prices and the extent of RW on TCs.

Changes in wholesale prices affect TC estimates in exactly the same way (but with the opposite sign) as do changes in utility variable production costs. For example, a decrease in wholesale price will reduce the amount of power the utility sells on the market and will increase the amount of power it buys in exactly the same way that an equal increase in production costs would. Because of this symmetry, we show results only for changes in wholesale prices. As wholesale prices increase, the losses caused by RW decrease (Fig. 9). Indeed, if wholesale prices increase by more than 1.6¢/kWh above their base-case values, RW *increases* earnings to utility shareholders. Conversely, as wholesale prices decrease, TCs increase.

As the number of customers that leave the utility increases, the TC amount increases. The loss to the utility increases linearly with the number of RW customers (i.e., the loss per RW customer is invariant with the amount of RW). The loss to remaining customers, however, increases much more rapidly. This difference occurs because, as the number of RW customers increases, the number of remaining retail customers among whom the loss is spread decreases.

Fig. 9. Effects of changes in wholesale electricity prices on the losses faced by utility shareholders.

ACCOUNTING FACTORS

We define accounting costs as those factors that have no effect on the utility's interactions with the wholesale market. Instead, these factors affect only the utility's income statement and balance sheet.

Our base-case utility has \$800 million in regulatory assets, compared with total assets in 1995 of \$4,950 million. Increasing the regulatory assets by 50% increases losses by 9% (Table 6). The base-case utility spends \$40 million a year on public-policy programs, equivalent to 2% of revenues. Eliminating these programs and their costs would cut TCs by 4%.

Increasing the fixed O&M costs of generation increases transition costs. A change in fixed costs of \$37/kW-year is equivalent to a 1¢/kWh change in utility production costs. A \$10/kW increase in fixed costs raises TCs by 10%, comparable to the effect of a 0.25¢/kWh change in either marginal production cost or wholesale price.

Ancillary services are those functions performed by electrical generating, transmission, system-control, and distribution equipment and people to support the basic services of generating capacity, energy supply, and power delivery. These services cost about 0.4¢/kWh (Kirby and Hirst 1996). Generating capacity accounts for many of these services and their costs. A utility that can sell these ancillary services to RW customers can use the fixed-cost portion of these revenues to offset what would otherwise be stranded costs. Each 0.1¢/kWh of ancillary-services charge reduces its losses by 3%.

Changes in inflation rate, customer load factors, T&D losses, or load growth all have very small effects on TC estimates, as shown in Table 6.

Table 6. Effects of various accounting factors on estimates of transition-cost losses

Factor (base case)	Change	Effect on TCs (% change from base case)
Regulatory assets (\$800 million)	-\$400 million	-9
Public-policy program costs (\$40 million/yr)	-\$40 million/yr	-4
Fixed production costs (\$42.5/kW-yr)	+\$10/kW-yr	+10
Age of generating units (16 years)	+1 year	-3
Ancillary-services charge (0.0¢/kWh)	+0.2¢/kWh	-6
Inflation rate (3%/year)	+1%/year	-1
Load factor (56%)	+5 % points	+1
T&D losses (7% energy, 12% demand)	+2% points	0
Load growth (1.4%/year)	+1%/year	-1

SUMMARY

The analyses discussed above show that, although many factors affect estimates of transition costs, only a few factors really matter (Fig. 10). The key variables that most affect losses include the year that RW begins, wholesale prices (or, equivalently, utility marginal production costs), the percentage of customers that wheel, fixed production costs, regulatory assets, and charges for certain ancillary services. Many other factors, including frequency and type of rate cases, public-policy-program costs, inflation rate, customer load factors, T&D loss factors, and load growth, have only small effects on the losses caused by RW.

Fig. 10. Effects of the key factors that influence transition costs. The base case against which these results are compared assumes that retail wheeling begins in 1996, the wholesale price is 2.5¢/kWh (and the marginal cost of the utility's generation is 2.4¢/kWh) in 1995, 50% of the commercial/industrial customers plus 25% of the residential customers are wheeling by the year 2000, fixed production costs are \$186/kW in 1995, and no ancillary-services charge is levied.

STRATEGIES TO ADDRESS TRANSITION COSTS

Given the large dollar amounts often associated with transition costs, regulators, utilities, their customers and suppliers, and others have a strong interest in seeking ways to offset these costs. Legislative and regulatory proposals for industry restructuring place TC policies among the centerpieces of their restructuring efforts (e.g., in California, Massachusetts, Texas, and Vermont). Strictly speaking, TCs, because they reflect sunk costs and future obligations, cannot be "mitigated." However, utilities and their regulators may be able to reduce other costs and thereby offset some of what would otherwise be TCs. Most of the strategies we identify involve shifting costs over time or among different segments of the economy.

We discuss four major types of strategies to address TCs: market actions, depreciation actions, rate-making actions, and utility cost reductions. See Baxter, Hadley, and Hirst (1996) for details on these and other strategies.

MARKET ACTIONS

Market actions affect the market structure for electricity or rely on market mechanisms, such as auctions or sales, to affect the distribution of TCs. One strategy calls for the rapid and broad opening of retail electricity markets (i.e., RW) at the earliest possible date. Monopoly franchises for retail electricity sales would be eliminated, and all consumers would have a choice of electricity suppliers. Such a strategy would maximize competitive pressures on suppliers and maximize consumer welfare gains (Flaim 1994).

An alternate strategy is to delay the onset of competition. The delay would not be indefinite, but would involve a more deliberate opening of retail electricity markets. Here retail access would proceed in a staged fashion, with only certain customer segments initially getting access to alternate suppliers (Flaim 1994). Retail access would eventually be granted to all consumers, but not until several years after the initial group got access. A variant on this strategy would be to give all consumers access at the same time, but to delay the onset of access by several years. This strategy sacrifices some consumer welfare gains to allow utilities to recover a larger share of their sunk costs.

Divestiture, selling all or part of a utility's generation portfolio to separate companies (affiliated or unaffiliated), is a widely discussed strategy (Rose 1995). Divestiture could address several issues. The sale would provide a readily identifiable market value for the asset(s), which is necessary to estimate TCs, and also separate the unregulated generation business from the regulated T&D business. Some analysts argue that utility divestiture is necessary to ensure

competitive markets and to reduce potential conflicts between unregulated and regulated business operations. Divestiture would also reduce the possibility that a utility will exercise market power from a monopoly market (transmission) to a competitive generation market.

A divestiture strategy is most commonly suggested for generation, but analysts also discuss the sale of transmission assets. (Revaluing generation, transmission, and distribution assets is a similar strategy except that the utility retains ownership of all assets.) This discussion is motivated by the belief that the market value of transmission assets exceeds their book value. In such cases, the above-book proceeds from a transmission sale are used to partially offset the below-book market values of certain generating assets. Setting aside potential legal issues (Hempling, Rose, and Burns 1994), problems arise for transmission-poor utilities that are faced with potential TCs.

Marketing excess capacity or energy, or capacity or energy freed by departing customers, is a clear strategy to increase revenues and help offset TCs. Indeed, FERC's (1996a) TC-estimation approach defines mitigation as the sale of available energy at market prices. Some proposals, including FERC's, give departing customers the opportunity to market energy freed by their departure from the utility.

Finally, improving system load factors, either by reducing peak demand or by increasing offpeak energy sales, should lower utility costs. Such a marketing strategy should affect the amounts of TCs a utility will face.

We now quantify several of these market actions (Table 7 and Fig. 11). Consistent with the results presented in the prior chapter, we analyze TCs as if they all fall on utility shareholders. In this chapter, however, we generally assessed the effects of different strategies by introducing each strategy to the RW case *only* (rather than to *both* the RW case and the reference case) and then comparing the results to the RW case without the strategy. Our intent is to estimate the financial effects of each strategy on a utility under retail competition. Thus, the results in Tables 6 and 7 sometimes differ (e.g., for load growth and load factor).

For the base case discussed above, a 2-year delay in the start of RW (i.e., from 1996 to 1998) reduces the utility's losses by 33%. A 2-year delay, combined with a 50% reduction in the ultimate amount of RW (i.e., from 50 to 25% of the commercial/industrial customers and from 25 to 12.5% of the residential customers) would cut the utility's losses by 70%. On the other hand, accelerating full implementation of RW by two years, from 2000 to 1998, would increase the utility's TCs by 72%.

Table 7. The effects of different strategies to address transition costs

Transition-cost strategy	% change in utility transition costs ^a
Market actions	
Accelerate RW with full implementation by 1998 instead of 2000	+72
Delay RW by two years	-33
Delay RW by two years and cut amounts by 50%	-70
Increase system load factor 5 percentage points (from 56 to 61%) by cutting peak demands	+20
Increase sales by 10% and hold system peaks unchanged (increase load factor from 56 to 62%)	-17
Charge 0.2¢/kWh for capacity-related ancillary services	-6
Depreciation options	
Accelerate depreciation schedules for nuclear (9 years) and coal (16 years) plants and for regulatory assets (6 years)	+34
Accelerate depreciation schedules for nuclear (9 years) and coal (16 years) plants and for regulatory assets (6 years); extend depreciation from 50 to 75 years for T&D	+28
Utility-cost reductions	
Lower customer-service costs from \$70 to \$45/customer-year	-13
Lower A&G costs from \$176 to \$100/customer-year	-37
Lower T&D O&M costs from \$23 to \$11/kW-year	-28
Lower fixed O&M costs for nuclear and coal plants by \$10/kW-year	-16
Make must-run contract dispatchable at 3¢/kWh and pay owner lost profits	-9
Lower fixed costs for power-purchase contracts from \$45 to \$30/kW-year	-12

^aThe base-case TCs total \$699 million, equivalent to 45% of shareholder equity.

If the utility is able to cut peak demands without affecting sales, its load factor will increase. An 8% reduction in peak demand yields an increase in system load factor from 56 to 61%. Although such a strategy lowers utility costs and average retail prices, the revenue reductions are greater than the cost reductions. Cutting peak demand increases the utility's TCs by 20%. On the other hand, if the utility improves its system load factor by increasing off-peak sales by 10% while holding peak demand fixed, its costs will go down more than its revenues decline. In that case, its TCs will decline by 17%. The difference in results between these two cases occurs because of the utility's retail tariffs. We ran these cases assuming no changes in

the customer, demand, and energy charges that retail customers face; these results suggest that the utility, with approval from its PUC, may want to revise these allocations in response to changes in system load factor. The effects of load growth on TCs shown in Tables 6 and 7 differ, but only in degree. Table 6 reflects the effect of an increase in the annual growth rate of electricity use from 1.4 to 2.4%/year. Over long periods, a 1%/year increase in a growth rate will lead to substantially greater demand. But over the 10-year period used in our analysis, the differences are not great. After five years, for example, demand growing at 2.4%/year will only be about 5% greater than if it had grown at 1.4%/year. In contrast, Table 7 presents a case where demand jumps 10% in the first year of RW, rather than increasing about 1%. The results indicate that large changes in demand can have important effects on TCs.

Finally, the utility might be able to sell generation-related ancillary services, such as regulation and operating reserves. We assume here that the utility can sell these capacity-related services for 0.2¢/kWh more than the operating costs of these services. Selling these services to wheeling customers would cut TCs by 6%.

Fig. 11. Effects of market actions on utility transition costs.

DEPRECIATION OPTIONS

Depreciation expenses for unamortized generation plant contribute directly to fixed generation costs. As a result, analysts have devoted considerable attention to examining how plant depreciation could be modified to address TCs. The depreciation options we review are

all, strictly speaking, rate-making actions. We place depreciation in a separate category to recognize the attention these strategies have attracted in TC debates.

Traditional regulation permits lengthy depreciation periods for the capital-intensive investments in generating facilities. For large power plants, these depreciation schedules may run over 30 or 40 years. Accelerating a depreciation schedule shortens the time over which capital costs are recovered. All things being equal, accelerated book depreciation increases depreciation expenses over the shortened depreciation schedule, but eliminates these expenses once the plant is fully amortized. The primary motivations for accelerated depreciation are to increase the recovery of a utility's fixed costs while its retail franchise is still intact and perhaps to decrease taxes in the short term (RDI 1994). Accelerated depreciation will affect the utility's income taxes, depending on each asset's original book depreciation schedule and when accelerated depreciation begins and ends relative to this original schedule. Depending on these schedules and the analysis period, the net effect on income taxes could be positive or negative.

Because accelerated depreciation increases depreciation costs immediately, an alternative is to offset these cost increases by decelerating depreciation of other utility assets (Hempling, Rose, and Burns 1994). For most utilities, the T&D plant is the largest capital asset after generation. Thus, one strategy is to offset the increased costs of accelerated depreciation by decelerating depreciation of transmission or distribution assets, or both. Southern California Edison (1994) proposed such a strategy to more rapidly recover shareholder investment in a nuclear plant and still hold retail rates constant.

A depreciation reserve is the accumulated annual depreciation expense on a utility's balance sheet that is deducted from the plant-in-service account. The depreciation reserve reflects the amount of investment in plant in service that has been recovered from ratepayers. Transferring depreciation reserves from T&D accounts to generation-plant accounts is an explicit strategy to revalue the associated assets. Such a transfer will reduce the net book value of the generation plant and increase the net book value of the T&D plant by the amount transferred. South Carolina Electric & Gas proposed this strategy to reduce the net book value of a nuclear plant to the average for nuclear plants in the region (South Carolina Public Service Commission 1996). FERC (1996b) rejected this proposal because it would shift costs from generation to transmission. The proposal would have shifted costs from the utility's retail customers to its wholesale transmission customers and, thereby, fails to comply with FERC's stranded-cost-recovery rules in Order 888.

We now quantify several of these depreciation options (Table 7 and Fig. 12). In the base case, the 800-MW nuclear plant is not fully depreciated until 2009, and the 750-MW coal plant is not fully depreciated until 2016. Accelerating depreciation (beginning in 1996) so that both plants are fully depreciated by 2000 raises TCs by 30% (16% from the nuclear plant and 14% from the coal plant). This strategy increases losses for the first several years (through 2000) and then reduces losses thereafter. However, the NPV of the increases are greater than the NPV of

the decreases. If the utility had been able to begin accelerated depreciation a few years *before* RW began, this strategy would have reduced the utility's exposure to TCs.

The utility has regulatory assets that total \$800 million as of 1995. Accelerating the depreciation of these assets from 12 to 6 years increases TCs by almost 4%. The utility's losses increase because more of the depreciation occurs earlier and therefore has a larger effect on the NPV of the losses. However, if this asset was depreciated even faster, over four or fewer years, the utility's TCs would decline. In this case, most of the costs associated with the regulatory asset would be recovered before many of the utility's customers are eligible for RW.

Extending the book-depreciation lifetime of T&D assets from 50 to 75 years reduces utility losses. Such a strategy can help to mitigate the effects of accelerated depreciation of generation assets. In this case, the combined strategy increases the utility's loss by 28%, 6 percentage points less than would occur without the extended T&D depreciation schedules.

Fig. 12. Effects of depreciation options on utility transition costs.

RATE-MAKING ACTIONS

Under traditional regulation, authorization to recover generation costs is granted in rate cases. Because rates and embedded-cost recovery are so closely connected, many TC strategies rely on rate-making actions.

In most jurisdictions, current rate design recovers variable costs and some portion of fixed costs through a volumetric energy charge. Even for those customers that pay demand charges, some fixed costs are recovered through the energy charge. Designing a tariff for all ratepayers that includes an energy rate close to the utility's marginal costs and a fixed charge close to the utility's fixed costs represents a more accurate price signal. The utility would then be able to compete successfully for sales during times when the utility is the low-cost provider, thus avoiding uneconomical bypass of the utility's generation system. Valle and Bidwell (1995) note that the lower energy rate that will result for most utilities from such a rate restructuring will also increase electricity demand. Any such demand increase will increase revenues and, as a result, reduce TCs.

Perhaps the simplest example of rate unbundling is the rate-restructuring option described above, which provides more appropriate price signals to consumers. Electricity services and costs can be further unbundled to include T&D costs and ancillary-services costs. Unbundling generation services in addition to power delivery, energy, and capacity may help address transition costs. For example, while the costs of ancillary services are a small part of a utility's total costs, charging for these costs may reduce TCs (Table 7 and Figure 11).

Performance-based rate making (PBR) replaces cost-of-service rate making with either a price or revenue cap that can be adjusted periodically for inflation and a minimum productivity-improvement target. A PBR mechanism that shifts market risks from consumers to the utility could encourage the utility to reduce costs and improve productivity (Comnes et al. 1995). PBR is attractive as a TC strategy when some of these cost savings are credited toward the utility's TCs.

Exit fees paid by departing customers are the opposite of charging captive customers for TCs. Most, but not all, proposals link the exit fee to those embedded utility costs incurred on behalf of the departing customer (Hempling, Rose, and Burns 1994). Exit fees can be structured as a lump-sum payment or a stream of payments. The exit-fee strategy attracts considerable interest from utilities and regulators, and is the strategy FERC (1996a) selected to address TCs for wholesale customers. A properly structured exit fee makes the utility indifferent (with regard to recovering the utility's historical investment on the customer's behalf) to a customer's decision to leave or stay and discourages uneconomical bypass of the utility's system.

Access charges for transmission or distribution service can be structured to include TC recovery. The access charges can be fixed (\$/customer or \$/kW-month) or volumetric (¢/kWh). The fixed charges could be collected as a lump sum or as a payment stream. Charges set for transmission access are under FERC jurisdiction, while charges for distribution access are under state jurisdiction. Access charges are appealing because they recover TCs from all electricity users except those few that are completely disconnected from the utility grid. This is the approach selected by the California Legislature (1996) in its specification of a competition transition charge.

Rose (1995) describes an access charge that applies only to departing customers. This option resembles an exit fee, except that the access charge is tied to a continued service provided by the utility seeking to recover costs from the departing customer.

To examine the effects of exit fees, we estimated one-time exit fees for residential and commercial/industrial customers in two ways (Table 8). First, we based the exit fee on the utility's losses during the first year of RW (1996) and assumed that the utility would be entitled to that amount for each of the 10 years in the original cost-recovery period. Second, we based the exit fee on the utility losses for each of the 10 years. The first approach led to higher exit fees, which would overcompensate the utility for its losses. This overcompensation is a consequence of the declines from year to year in annual TCs, which drop because of load growth, decreases in depreciation expense, and increases in wholesale prices (Fig. 7).

Table 8. Exit fees (in dollars) that departing retail customers would pay to compensate the utility for its transition costs

Exit fee based on:	Residential	Commercial/Industrial
1996 losses	1,625	19,200
Annual losses, 1996-2005	1,370	15,600

Some regulators (e.g., Hanger 1996) are considering the option of allowing utilities a return of their stranded investment (e.g., depreciation) but not a return on their stranded investment (see Chapter 8). Denying our base-case utility its authorized 11.5% ROE on these investments would reduce the amount of TCs its customers would otherwise face by 17%. In other words, shareholder returns account for 17% of the TCs that the utility faces.

UTILITY COST REDUCTIONS

As with depreciation options, utility cost-reducing options can also be categorized as rate-making actions. To be considered as TC strategies, most of the following options require regulatory approval to allow cost reductions (particularly those achieved in nongeneration operations) to be used to offset TCs. Cost reductions that enhance the quality and level of service provided are economic-efficiency gains, and thus are distinguished from strategies that shift costs over time or among different economic actors.

Generation-cost savings could come from reducing plant heat rates and O&M costs and from retiring uneconomical plants. Competitive forces from a restructured electricity-generation industry will induce utilities to pursue these cost-reducing activities to retain existing customers and to attract new ones. However, these cost-cutting pressures raise concerns among some industry observers that plant maintenance and safety will suffer, particularly for nuclear plants (Kahn 1994). Utilities will also be motivated to reduce costs in other areas, such as T&D and

customer service, if these reductions decrease TCs for shareholders. Recent work suggests that the cost-reduction potential in nongeneration operations may be substantial for some utilities (Baxter, Hadley, and Hirst 1996).

Utilities with above-market power-purchase contracts can reduce costs by restructuring these contracts. Depending on the history of the specific contract and the utility's financial status, the utility may be able to restructure the contract or buy out the above-market portion of the contract at a discount. Power producers will have incentives to renegotiate contracts if maintaining the full provisions of the existing contracts threatens the financial survival of the purchasing utility. In addition, provisions of certain power-purchase contracts may become incentives to renegotiate once a competitive generation market is established. Finally, depending on their debt costs and discount rates, some producers may prefer a contract buyout with up-front payments rather than continuing to receive payments over extended periods during a time of substantial changes in market structure and operation.

We quantify several of these utility-cost options in Table 7 and Figs. 13 and 14. For customer-service, administrative and general, T&D, and generation fixed O&M costs, we used the performance benchmarks developed by Baxter, Hadley, and Hirst (1996) as the reference point; see Table 5 of their report.

If the utility could lower its customer-service costs from \$70 to \$45/customer-year, its losses would drop by 13% (Fig. 13). Of course, competition may compel companies to increase customer-service costs to advertise and deliver new services. Our example illustrates the potential savings from delivering historical services more efficiently. If it could cut its administrative and general costs from \$176 to \$100/customer-year, its TCs would drop by 37%. Finally, cutting its T&D O&M costs from \$23 to \$11/kW-year would cut losses by 28%.

If the utility lowers the fixed O&M costs for its nuclear and coal units by \$10/kW-year, its losses will drop 16% (Fig. 14). If the must-run 600-MW contract can be dispatched at its running cost (assumed to be 0.3¢/kWh below its contract payment of 3.3¢/kWh, its capacity factor will decline from 75% to 17%. The savings that accrue from the utility's ability to obtain cheaper electricity from its own plants and from other purchases is equivalent to 19% of its losses. If, as seems more realistic, it must compensate the owner of this contract for its earnings losses, the utility's losses are cut by only half as much. Finally, if the utility can lower the fixed payments from \$45 to \$30/kW-year for the 1600-MW it has under contract, its TCs will decline by 12%.

Fig. 13. Effects of nongeneration cost reductions on utility transition costs.

Fig. 14. Effects of generation cost reductions on utility transition costs. Contract 1 is the must-run unit.

Whether the kinds of cost reductions outlined above are reasonable depends on the individual circumstances facing each utility. For example, a utility might have high distribution costs not because it is inefficient but because its customer density is low or its geographic area is subject to extensive and destructive storms. Berndt, Doane, and Epstein (1995) analyzed data from 99 utilities and concluded that the most important determinant of differences in electricity prices across utilities is per-customer levels of electricity use. That is, utilities in areas with mild weather and low consumption have high electricity prices. These results suggest that the potential for cost reductions is less than what one might otherwise estimate. On the other hand, competitive forces might be a powerful stimulant to innovative cost-cutting.

TRANSITION-COST STRATEGIES IN PRACTICE

Most of the above assessments consider the effects of individual strategies. Comprehensive approaches to TCs are likely to consider combinations of strategies. The choice of strategies will be closely related to the source(s) of the TCs and the allocation of TCs to different parties for cost recovery (see Chapter 8).

To illustrate, consider California's TC policy (California Legislature 1996). The larger strategy depends on unbundling retail rates and the creation of an access charge, called the competition transition charge. All customers must pay this charge to receive distribution services. Another important element is a multiyear rate freeze for all customer classes. (The rate freeze for small customers is implemented after a mandated 10% rate reduction.) Utility cost reductions beyond those needed to keep costs in line with rates may be credited against TCs. Utilities are encouraged to accelerate depreciation of generation assets, but the rate freeze prevents the utility from passing any cost increases to customers. Utilities can recover TCs associated with utility-owned generation through 2001. Any remaining costs after this point must be recovered from market revenues. In addition, the proposal secures a substantial portion of TCs by authorizing the sale of bonds by the California Infrastructure and Economic Development Bank. This proposal is analogous to the strategy Puget Power used to secure recovery of certain regulatory assets (Kelly and Gaines 1995).

SUMMARY

The results discussed above apply only to the hypothetical utility we created. The benefits and costs of the different strategies discussed here will depend on the utility's specific situation concerning its above-market costs in utility-owned generating units, long-term contractual obligations, and regulatory assets.

A few of the strategies discussed here have the potential to substantially affect the TCs that a utility would otherwise face. Changes in the start date, pace, and extent of RW could have large effects in shifting costs between utility shareholders and retail customers. Charging an exit fee to departing customers would have comparable effects. Cutting various nongeneration O&M

costs as well as the nonfuel O&M costs for generating units could also have substantial cost-reduction effects, although the savings for the utility analyzed here may be unusually large.

At the other end of the spectrum, extending the book-depreciation schedules for a utility's T&D investments is likely to have only small effects on TC amounts. (Indeed, all the options that shift costs over time or across different groups do not affect total transition costs.) Similarly, shortening the depreciation period for regulatory assets also has only a limited effect on a utility's TCs. Finally, charging wheeling customers for ancillary services will have a modest effect on TCs.

WHO WILL (SHOULD) PAY TRANSITION COSTS?

Perhaps the most important, and difficult, TC issue facing regulators is deciding how to allocate nonmitigable transition costs among the various parties. Not surprisingly, debates at the state and federal level on this issue have been quite heated. In part, this controversy is a consequence of the large dollar amounts at stake. It may also be a consequence of the strong policy, rather than scientific, basis for deciding this issue. In other words, science has little to contribute to legislative and regulatory decisions concerning the allocation of these costs. Opinions differ strongly on whether utilities are entitled to full recovery of their TCs. Large industrial customers, consumer advocates, and some regulators argue that there is no constitutional entitlement to the recovery of such costs; indeed, these costs should be subject to the same types of prudence and used-and-useful criteria that commissions have long applied to utility actions. On the other hand, many utilities argue that the Takings Clause of the U.S. Constitution requires full compensation for such costs; they suggest that these costs were incurred with the approval of regulators.

PRORECOVERY ARGUMENTS

The primary proponents of the argument that utilities are entitled to and should receive full recovery of their transition costs are, not surprisingly, the investor-owned utilities themselves. Baumol, Joskow, and Kahn (1994) offer arguments, based on economics and regulatory policy, supporting shareholder recovery of TCs. They suggest that increasing economic efficiency should be the primary objective of restructuring the electricity industry. They argue that, when properly structured, competitive markets are more likely to increase economic efficiency than are regulated markets. These efficiency gains will involve both productive efficiency (i.e., providing goods at minimum cost) and allocative efficiency (setting prices correctly, based on marginal costs).

The authors argue that unless TCs are properly addressed, the efficiency gains from competition may be eroded. The authors' primary conclusion is that equity and productive efficiency considerations support a policy of full TC recovery for utility shareholders. On the equity side, the authors believe that shareholders have not previously received compensation from their allowed equity returns for the risk they now face of not being able to recover their investments because of changes in government policy. Further, they note that utilities incurred most of these costs with the full approval, and sometimes at the mandate, of regulators. Should shareholders fail to recover TCs, the efficiency consequences include distortion of competition between utilities and alternative suppliers, extension of the transition to competition, and the possibility of increased capital costs to the electricity industry.

The authors indicate that TC recovery can be compatible with efficient competition when the recovery mechanism is properly structured. To ensure that competition between rival suppliers is based on efficiency, the authors recommend that the costs of historical obligations be assessed from all customers who have benefited from these obligations.

Rowe and Graening (1996) develop legal arguments to justify full payment to utility shareholders of TCs.* On the basis of the Takings Clause of the Fifth Amendment, they argue that the government may require private property owners to cede rights to that property to serve the public good, but it must then ensure just compensation to the owner. Paying transmission owners the embedded costs of their transmission system is irrelevant, in part because transmission is an integral part of a utility's larger generation, transmission, and distribution system. Allowing others to use a utility's transmission system adversely affects the value of a utility's generation assets, and for this reduction in value the utility is entitled to full compensation. Rowe and Graening write:

The integration of distribution, transmission and generation into a tightly woven commodity delivery system performs as a whole. One part severed from the others can drastically reduce the property's comprehensive value. If the wires are severed from the generation, their loss will destabilize the value of the overall property. The result would be akin to a tricycle with only two wheels—broken and going nowhere.

Kolbe and Tye (1996) argue that the rates of return historically allowed by state PUCs were insufficient to compensate shareholders for the risk associated with retail competition. For utility shareholders to have been automatically compensated by regulators for the risk of TCs, the allowed rate of return would have had to have been much higher than the actual cost of capital. Further, the increment above the cost of capital is very case specific (i.e., it depends on the particular situation facing that utility). Kolbe and Tye believe it is unlikely that PUCs were performing the necessary company-specific calculations to determine the authorized ROE.

ANTIRECOVERY ARGUMENTS

Large industrial customers (Electricity Consumers Resource Council 1995) and low-cost utilities (IPALCO 1995), among others, oppose payment of full TCs to utilities. They argue that such payments will have anticompetitive and uneconomical consequences by providing payments to high-cost producers that will discriminate against low-cost producers. Full-cost recovery also ignores any utility responsibility for these costs and their consequent obligation to pay for at least some of them. Navarro (1996) believes that allowing full recovery of TCs is

* An exchange of letters between Randazzo and authors Rowe and Graening in the October 1996 issue of *The Electricity Journal* indicate how complicated and contentious these constitutional issues are. See also Schotland (1996) and Massachusetts Department of Public Utilities (1996).

unfair to consumers, would provide a shield for high-cost producers and discriminate against low-cost producers, and would reward utilities for past "bad management decisions."*

Rose (1996) argues that TC recovery by utility shareholders is not supported on grounds of either economic efficiency or historical regulatory policy. He states that the concept of transition costs, and arguments for its recovery by utility shareholders, has little basis in economic theory, legal precedence, or precedence in other deregulated industries.

Rose first considers the argument that TC recovery is required for economic efficiency. This argument is based on a narrow definition of efficiency—preventing uneconomical bypass of the utility's system (i.e., selecting another supplier when the utility is the lowest-cost provider for that customer). He argues instead for a broader perspective on efficiency, one that considers the long-term promotion of competitive markets and incentives for suppliers to minimize costs over time. In his view, longer-term gains from price reductions to consumers are likely to exceed the shorter-term losses from uneconomical bypass. Allowing TC recovery may impair the development of competitive markets by reducing utility incentives to lower costs, acting as a barrier to entry and exit of other suppliers in the marketplace, and creating an asymmetry between utility risk and reward. Finally, even if competitive forces lead to utility bankruptcies, society's resources will be more efficiently allocated after the financial readjustments bankruptcies will bring.

Rose next considers the argument that cost recovery is required to comply with historical regulatory policy (i.e., the "regulatory compact"). He discusses differing interpretations of this compact and concludes that full TC recovery would be inconsistent with historical regulatory policy in many states. The only entitlement granted to utilities is the revocable privilege to serve an exclusive territory, from which stems the obligation to serve. This entitlement is not an agreement to pay all prudent (and other) costs; customers have no reciprocal obligation to purchase from the utility unless a written contract is in place.

Bradford (1996) believes, in contrast to Kolbe and Tye (1996), that utility shareholders historically have been compensated at levels high enough to cover the risks of some loss on strandable investments. Indeed, between 1977 and 1991, the annual total return to shareholders for 81 utilities averaged 13.3% per year, higher than the 13.2% for unregulated industrial firms even though electric-utility stocks were less risky than the market as a whole (Michaels 1996).

GOVERNMENT DECISIONS

At the federal level, the Council of Economic Advisers (1996) favors utility recovery of transition costs:

*Michaels (1996) notes that almost all of the stranded nuclear investment comes from 34 plants that were completed after 1984. By that time, Michaels argues, utilities should have known that such plants were far too costly to build and, in many cases, were not needed at all.

In unregulated markets the possibility of stranded costs typically does not raise an issue for public policy—it is simply one of the risks of doing business. However, there is an important difference between regulated and unregulated markets. Unregulated firms bear the risk of stranded costs but are entitled to high profits if things go unexpectedly well. In contrast, utilities have been limited to regulated rates, intended to yield no more than a fair return on their investments. If competition were unexpectedly allowed, utilities would be exposed to low returns without having had the chance to reap the full expected returns in good times, thus denying them the return promised to induce the initial investment. A strong case therefore can be made for allowing utilities to recover stranded costs where these costs arise from after-the-fact mistakes or changes in regulatory philosophy toward competition, as long as the investments were initially authorized by regulators. ... The case for allowing recovery is even stronger where stranded costs arise from regulatory obligations imposed on utilities [such as QFs]. ... To be sure, utilities should be granted recovery only of costs prudently incurred pursuant to legal and regulatory obligations to serve the public.

FERC (1996a), in its Order 888, clearly favors utility recovery of “legitimate, prudent, and verifiable [wholesale] costs.” Similarly, the California PUC (1995) and the California Legislature (1996) both decided to allow utilities the opportunity to recover their retail transition costs. FERC provides an extensive discussion of the many comments it received on this issue, both for and against cost recovery, and the basis for its decision to allow utilities the opportunity to recover all their TCs.

FERC’s decision limits utility cost recovery to only those that can be directly attributable to Order 888 mandating open-access transmission. If, for example, a wholesale customer physically leaves a utility’s service area, the utility’s losses associated with this departure would not qualify for cost recovery under FERC’s rule. In addition, FERC limited recovery to costs incurred prior to July 11, 1994, the date of its original stranded-cost notice of proposed rulemaking. Finally, FERC requires a utility to demonstrate that it had a “reasonable expectation” that it would continue to serve the departing wholesale customer for a certain amount of time. Thus, although FERC decided to allow utilities the opportunity to recover 100% of the costs stranded by increased transmission access, FERC limited these opportunities to those that are a direct consequence of its actions.

Both FERC and California dealt with the allocation of costs among parties. With respect to the utilities themselves, both entities put in place mechanisms to encourage utilities to cut costs (see Chapter 7). FERC ruled that departing wholesale customers will pay the transition costs associated with their departure. This decision ensures that neither utility shareholders nor other wholesale customers bear the costs associated with a particular customer’s departure.

The California Legislature (1996) sought to ensure that residential and small commercial customers would benefit from restructuring that state's electricity industry. To that end, the legislature authorized the issuance of up to \$10 billion of government bonds, the proceeds of which would be used to guarantee residential customers a minimum 10% rate reduction and help pay for TCs. The lower interest rate on government vs utility bonds, the longer amortization period (10 vs 5 years), the exemption from state income taxes, plus the possibility of an exemption from federal income taxes will be used to provide the rate reduction to residential customers.* The Legislature decided that all retail customers will pay for transition costs through a nonbypassable competition transition charge, allocated across rate classes in a manner similar to the cost allocation in place as of June 1996. The California legislation is important because it provides the utilities with strong assurances for recovering a substantial portion of their transition costs and it "securitizes" some of these costs in a way that reduces their magnitude.

The Pennsylvania General Assembly (1996) authorized the Pennsylvania PUC to issue qualified rate orders to utilities for the issuance of transition bonds. As in California, these bonds would require a lower interest rate because of the state's backing:

Notwithstanding any other provision of law, the Commission has the power to specify that all or a portion of a qualified rate order shall be irrevocable. To the extent specified, neither the order nor the intangible transition charges authorized to be imposed and collected under the order shall be subject to reduction, postponement, impairment of termination by any subsequent action of the Commission. ... The Commonwealth will not limit, or alter or in any way impair or reduce the value of intangible transition property or intangible transition charges approved by a qualified rate order until the transition bonds and interest on the transition bonds are fully paid and discharged or the contracts are fully performed on the part of the electric utility.

Hanger (1996), a Pennsylvania PUC Commissioner, suggests "different recovery levels for different types of stranded investments." Commissions can consider the degree of utility-management responsibility for the TCs that exist in each category. In addition, the transition costs associated with utility-owned generation assets includes 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 TCs, for example. Alternatively, commissions may allow only a return of

*These securitization benefits have a cost: the state *guarantees* that retail electricity consumers will pay the interest and principal associated with these bonds.

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.*

The New Hampshire PUC (1996) and the Vermont Public Service Board (1996) adopted TC positions more favorable to customers and less favorable to utility shareholders than did FERC or California. The New Hampshire PUC noted that, with the exception of purchases from QFs, the "New Hampshire electric utilities' historical prerogative to make resource decisions have not been significantly compromised by legislators or regulators." The Commission proposed to use New England regional electric rates as a key element in determining the amount of TCs that individual utilities could recover. That is, the utilities in the worst financial shape, as measured by their retail rates, will get the least relief in TC recovery. Specifically, the Commission stated that "it is our preliminary view that utilities with rates at or below the regional average should be provided a greater opportunity to recover net, verifiable, nonmitigable stranded costs than should utilities with rates above the regional average." The Commission reasoned that each New Hampshire utility operated under comparable economic and regulatory conditions, including participation in the same power pool, access to the same fuel markets, and the requirement to conform to the same state laws and regulations. Given these similar operating environments, one can assume that differences in utility rates are attributable primarily to utility-management decisions.#

The Vermont Public Service Board (1996) is especially concerned about transition costs because rates in Vermont are increasing at the same time that they are decreasing in other New England states. The difference is primarily a consequence of the \$4 billion, 30-year contracts that the Vermont utilities signed several years ago with Hydro-Quebec. These contracts account for about 60% of the transition costs for the Vermont utilities.

The Board notes that the transition to competitive electricity markets may provide "substantial *opportunities* for utilities," which can be used to offset what would otherwise be TCs.§ The Board also plans to limit TC recovery to a five-to-ten-year transition period. It

*Rohrbach (1996) showed how regulatory decisions on recovery of 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 ROE to 90% of the interest rate on long-term debt lowers the cost to 8.0¢/kWh, allowing zero ROE lowers the cost to 7.0¢/kWh, and eliminating both ROE 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 New Hampshire PUC's plan responded to state legislation (H.B. 1392) that replaced the "just and reasonable" standard for utility-rate setting with a new "equitable, appropriate and balanced" standard.

§The Massachusetts Department of Public Utilities (1996) also notes 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 overall market-to-book value for the common shares of 50 U.S. utilities was 1.4 as of June 1996 (Fleishman, Quartarolo, and Tan 1996). This high valuation by utility

emphasizes the utilities' obligations to mitigate TC amounts and offers to provide TC recovery only after all mitigation strategies have 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 (similar to the method planned for California).*

The regulatory and legislative decisions in favor of cost recovery may be motivated by both philosophical and practical reasons. Philosophically, the federal and California governments recognize that many of the utility decisions that led to above-market costs (especially the purchase of electricity from QFs) were actively promoted by government. Even where decisions were not promoted by governments, governments acknowledge that the regulatory commissions approved those actions. The Vermont and New Hampshire decisions, on the other hand, favor retail customers over utility shareholders and emphasize the historical and legal responsibility of utility managements for their resource-acquisition decisions.

Practically, it might be very difficult to implement a new industry structure without the support of utilities. If utilities were not permitted to recover most of their transition costs, they could find many ways to delay implementation of competitive markets. For example, although the Michigan Public Service Commission mandated a RW experiment in 1994, RW has yet to begin in that state. Thus, we speculate that utilities in many jurisdictions will be allowed to recover most, but certainly not 100%, of the TCs that they cannot reasonably mitigate.

The Massachusetts Department of Public Utilities (1996) took just such a pragmatic view in its recent order:

In this rulemaking, we have determined that the electric companies have not established a clear legal entitlement to stranded cost recovery. At the same time, we acknowledge that the legal question of whether stranded costs are recoverable in the restructuring of the electric industry is one that PUCs and the courts have never addressed, let alone resolved. It continues to be our belief that litigation over stranded cost recovery would delay the introduction and benefits of competition for consumers. Furthermore, as a matter of sound public policy, the

shareholders can be interpreted as a sign of confidence that regulators will allow considerable TC recovery, that utilities stand to gain in competitive electricity markets, or both.

*Some of these 11 strategies may not be considered mitigative in a strict sense. Specifically, economic operation, shutdown of uneconomical generating units, and cost reduction overlap; write-offs or write-downs shift costs to utility shareholders; and exchanges of underutilized assets are unlikely to yield book values, resulting in losses to utility shareholders.

Department reaffirms that allowing electric companies a reasonable opportunity to recover stranded costs is in the public interest because such recovery would: 1) ensure the provision of sound electric services during the transition to competition; 2) affirm reliability of commitments, which is an essential element in any future industry structure; 3) promote federal and state coordination and ensure equal treatment of similarly situated utilities; and 4) avoid costly, reform-delaying litigation.

In deciding on how much TCs a utility is entitled to recover from its customers, the Department will require full documentation on such costs from each utility, including sensitivity analyses.

Some utilities have generating assets whose book values are *below* market prices. Although this situation of negative TCs (i.e., what one might call transition benefits) 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 TCs should apply to negative TCs. As noted by the staff of the Texas PUC (1997), "In the transition to a competitive retail electricity market, to the extent utilities with *positive* [TCs] are granted recovery of such costs from ratepayers or otherwise, utilities with *negative* [TCs] should likewise be required to pass through to ratepayers the benefits of their low cost generation resources."

INTEGRATING COST RECOVERY WITH COMPETITIVE MARKETS

This chapter considers appropriate recovery mechanisms to use once a decision is made to allow a utility to recover some or all of its transition costs. The Texas PUC (1997) suggested that recovery mechanisms be assessed for their effects on rates, incentives to utilities to cut costs, effects on competitive electricity markets, and administrative simplicity. Equity and efficiency are two key criteria to consider in this regard.

Equity refers to the distributional consequences of a recovery mechanism. A recovery mechanism should allocate costs to parties in relation to their historical obligations and expectations. As an example, a per customer recovery charge levied without regard to the historical electricity use for each customer class (or each customer) would not pass this test.

Efficiency refers to the resource-allocation and market-operation implications of a recovery mechanism. A cost-recovery mechanism should not distort competition by affecting consumer choice among competing suppliers. Nor should a mechanism encourage high-cost generators to operate instead of low-cost units. A mechanism should not act as a barrier to entry for new suppliers (e.g., by making it profitable for an existing supplier to underprice a new entrant that has lower costs). A mechanism should encourage utilities to reduce the amount of TCs as much as possible (e.g., by retiring generating units that are uneconomical to operate and by renegotiating power-purchase and fuel-supply contracts). Finally, whatever mechanism is chosen should be simple to administer and should, to the extent possible, reduce the opportunities for litigation.

Most of the strategies discussed in Chapter 7 simply shift costs between economic actors and therefore fail one or both of these criteria. Rapidly opening retail markets may promote economic efficiency, for example, but in many cases may not be fair to utility shareholders. Delaying competition may benefit shareholders, but postpones the customer benefits that an efficient generation market can provide. Accelerating depreciation shifts future costs to today's ratepayers, and thus fails the equity test. Many tax measures also shift costs.

What options remain? Exit fees for departing customers (as FERC proposed) or access charges for all customers (as proposed in California and elsewhere) can be implemented in ways that are consistent with equity and efficiency principles. A precursor step for both approaches is to unbundle rates to enable customers to distinguish among the primary electricity services.

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 the avoidable and unavoidable components of embedded costs and should not be influenced by the form of TC recovery. Consider an example to see how these cost components should affect future decisions on generator operation or retirement and the amounts of TC recovery. This example is a slightly more detailed illustration of the principles developed in Chapter 2 (Fig. 5). In Chapter 2 we noted that generation-related TCs should be capped at the utility's average fixed generation costs. In the current example (Table 9), we further divide fixed costs into those that are avoidable (e.g., fixed O&M) and those that are unavoidable (e.g., interest payments). The 200-MW unit in question 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 (Table 9). Thus, TCs should be capped at \$4 million/year ($200 \text{ MW} \times \$20/\text{kW}$).

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 ($200 \text{ MW} \times 2500 \text{ hr} \times 2.1\text{¢}$) 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 TCs. Thus, this unit has transition 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 TCs 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 relative to demand, 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 TCs would amount to -\$400 thousand (i.e., a negative TC). This amount could be used to offset losses associated with other generating units.

As in Fig. 5, this example shows that the amount of TCs associated with a particular generator depends on the interactions between that unit and the competitive bulk-power market. It also suggests that regulators need to be careful in designing a TC-recovery mechanism to be sure that it does not distort what would otherwise be economically efficient decisions concerning the operation, shutdown, or retirement of the unit.

Table 9. Hypothetical example showing relationship between avoidable and unavoidable fixed costs and allowable transition costs^a

	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 TC	1,500	4,000	0

^aThis 200-MW generating unit has fuel plus variable O&M costs of 2.1¢/kWh, avoidable fixed O&M costs of \$10/kW-year, and unavoidable fixed (capital) costs of \$20/kW-year.

TRANSITION-COST RECOVERY: AN EXAMPLE

Joskow (1996) and Rose (1996) describe TC recovery mechanisms that are integrated with performance-based regulation approaches. Joskow focuses on the application of incentive regulation for generator performance under TC recovery. Rose discusses the use of incentive regulation for T&D services in conjunction with a TC recovery mechanism.

As noted in Chapter 2, suppliers must compete on the basis of marginal production costs for efficient competition to occur. Joskow uses this principle to suggest how TC recovery can be successfully integrated with competitive generation markets. The key is to ensure that suppliers compete on the basis of marginal costs rather than sunk costs. In the short run (i.e., with capital stocks and contractual obligations fixed), marginal costs include fuel and variable O&M needed (1) to maintain a generating unit's availability to supply and (2) to generate electricity. In the longer-term, marginal costs include the future capital costs for investments in existing or new generating units as well as the future fuel and nonfuel O&M needed to generate electricity. Generators with the lowest marginal costs should be preferred by consumers. Units with higher marginal costs should be dispatched or constructed only when demand has increased so that prices are high enough to make it profitable to use these resources to balance supply and demand. Within the constraints of contractual agreements, control-area

operators abide by this principle by dispatching generating units on the basis of their short-run variable costs; lowest-cost units are dispatched first.

In the short run, prices in competitive markets will approach the short-run marginal costs of supplying an additional unit of output at the output and price levels where supply and demand are balanced. These costs and prices will vary from hour to hour throughout a year as demand varies and the generating units used to meet demand change. All suppliers able to operate under these conditions will be paid these market-clearing prices. Suppliers with marginal costs below this price, the inframarginal suppliers, will earn short-term economic rents at this competitive price level. This rent is how suppliers recoup fixed capital costs.

Thus, to implement TC recovery and efficient competition requires two conditions. First, transition costs must be estimated so that suppliers are at risk for all future marginal costs. Second, all customers must pay TCs regardless of their choice of supplier (i.e., transition costs are nonbypassable).*

Joskow specifies the following components of each customer's electricity bill:

$$\begin{aligned} \text{Total electricity bill} = & \text{TC recovery charge} + (\text{T\&D rate} \times \text{Electricity use}) \\ & + (\text{Generation market price} \times \text{Electricity use}) . \end{aligned}$$

All customers must pay the first two components. The first component is an access charge or an exit fee. As illustrated in the previous section, this charge should be capped at the utility's unavoidable fixed generation costs. The second element pays for use of the utility's T&D system. The final component is based on the market price of generation service the customer obtains from the competitive market. This payment could be made to the host utility or to an alternative supplier if it offers a lower price. Each customer has an incentive to select a supplier that offers the lowest generation price because the other two charges are independent of the choice of generation supplier. The TC charge can be implemented as a fixed or volumetric charge. The key is to link the charge to the customer's overall electricity use, which is the best measure of the historical investment made by the utility on each customer's behalf.[#]

*Implementing a completely nonbypassable mechanism may not be possible. Customers will continue to have the competitive choices currently available to them, such as fuel switching, energy efficiency, self generation, and relocation outside the utility's service area.

[#]The linkage between TC recovery and electricity use is most equitable if future use closely resembles historical use. If, however, a customer expands use in the future, this should affect the last two components of the bill but not the first. If the recovery mechanism is implemented as a volumetric charge, the charge may go up or down depending on how the customer's current use deviates from historical levels. Whether new customers should pay the first component is a policy decision. Equity considerations argue against charging new customers for TCs. Administrative simplicity, however, may support a TC charge for all customers.

The utility's revenues are derived from the following sources:

$$\begin{aligned} \text{Net revenue} = & \text{TC recovered} + \\ & [(\text{T\&D rate} - \text{T\&D cost}) \times \text{Total electricity purchases by distribution customers}] \\ & + (\text{Generation market price} - \text{Utility's marginal generation cost}) \\ & \times \text{Electricity sales from utility's plants} . \end{aligned}$$

Under this system, the utility profits from its generation sales only when its marginal generation costs are below the generation market price. TC recovery is independent of whether the utility's plants operate or not. A key to this system is to estimate and unbundle the charges for transition costs. This unbundling enables generators to compete on the basis of marginal costs and not average costs. This basic approach is being proposed in California and Texas, among other states.

Joskow's example raises several implementation issues. Perhaps the most substantial issue is the need to estimate TCs. Only for regulatory assets, which have no market value, is this estimate easy to make. The primary difficulty is in determining the market value of a utility's generation assets. The earlier discussion on estimation approaches describes the many ways to estimate market value. Any of those approaches, when properly executed, could be used under this system.

Joskow's example uses an ongoing administrative method with three primary variables to consider: regulated value of assets, market price of electricity, and marginal costs and generator performance of the utility receiving TC recovery. The regulated value of assets is known. The main challenge here is to agree on which categories of assets, beyond utility-owned generation, should be included in the valuation. In Joskow's approach, the market price of electricity is based on observed market conditions over the defined transition period. The market price is derived from the operating revenue achieved by the generator, which is the observed sales times the market price.

The final variable to consider is the generator's avoidable costs. Joskow's suggestion is to establish an avoidable-cost performance standard that provides incentives for efficient behavior. The performance standard relies on target production-cost values for each plant (or for the portfolio of generators). The principal production-cost factors include plant availability, plant output (GWh), heat rate, fuel cost, and variable O&M cost. These targets can be adjusted according to agreed-upon indexes (e.g., general inflation or changes in a gas-price index) as conditions warrant. The performance standard is a form of incentive regulation for utility-plant performance. If utility operations exceed the target (i.e., if plant availability and generation are higher than expected or if plant heat rates, fuel costs, and O&M costs are lower than expected), then shareholders are rewarded. If the utility misses the targets, shareholders are penalized. To be effective, this mechanism must place shareholders at risk for recovering reasonable values for marginal generation costs. Such a mechanism provides utilities with incentives to lower these costs and make only profitable sales.

Returning to the equation that specifies the total customer bill, the TC recovery charge is estimated as follows:

$$\begin{aligned} \text{TC recovery charge} &= \text{TC/customer} - \\ &\quad (\text{Generation market price} - \text{Marginal-cost benchmark}) \\ &\quad \times \text{Utility generation sales to customer} . \end{aligned}$$

The second term is zero if the market price is less than the marginal-cost benchmark. In that case, the plant should not operate.

One of three situations can occur under this example. First, the utility does not make any generation sales to this customer, in which case the recovery charge equals the per-customer TC. Second, the utility makes some generation sales to the customer, and the generation market price is less than the utility marginal-cost benchmark, in which case the recovery charge again equals the per-customer TC. Third, the utility makes some generation sales to the customer and the generation market price exceeds the utility marginal-cost benchmark, in which case the per-customer TC will be reduced by this difference. In each case, these are the desired outcomes to promote competition on the basis of marginal production costs.

TRUE-UP MECHANISMS

An important problem with administrative valuation approaches is their reliance on forecasts of expected utility revenues, costs, and future market prices. One suggestion to reduce the risks from forecast errors is to reconcile, or true up, forecast and observed events and then to adjust future cost recovery by the outcome of this reconciliation. Under a true-up mechanism, any overcollection of TC payments is returned to payers (usually, but not always, the retail customers of a utility); any undercollection is recovered from payers. True ups may be conducted periodically (e.g., every year) or as a one-time event. True-up mechanisms can be applied regardless of whether the utility is authorized full or only partial recovery of its transition costs.

The amounts of TCs to be recovered from securitized bonds are *not* subject to true up. The low interest rates associated with such bonds is a consequence of their low risk, which in turn stems from the state's guarantee that customers will pay the required amounts over the life of the bonds.

TC determinations involve a comparison of book (i.e., regulated) asset value with market value. For generation assets, the result of this comparison is largely equal to a utility's sunk costs (i.e., its average fixed generation costs) minus any operating earnings on generation. (TC equals sunk costs only when the asset has a market value of zero.) Operating earnings are equal to a utility's generation revenue (generation sales times the market price for generation) minus avoidable generation costs. Thus, a true-up mechanism must address three major elements of

a TC forecast: the market price for generation output, the utility's generation sales, and the utility's operating costs for generation (fuel plus O&M costs).

Important questions arise about developing appropriate indexes for electricity market prices, especially in the short term. In theory, the equilibrium between supply and demand establishes a unique market price. In practice, working markets can support numerous prices for electricity. Should firm or nonfirm prices be used, for example? Spot market or bilateral contract prices are available, but are these appropriate indicators for the marginal generation cost? Power pools also provide price signals. Even here, the use of the pool price, which changes frequently, may not be straightforward. As Lesser and Ainspan (1996) note, in the future, asking for *the* market price of electricity may be like asking for *the* price of an airline ticket today. However, McCullough (1996) discusses several existing price indexes that regulators could use in such true ups.

The expected utility sales from generation is another major forecasting element subject to true up. Generation sales may be defined as the average of historical sales to the relevant customer(s) or output from a particular asset (generating unit or power-purchase contract) before the transition to competition. This is the approach FERC uses. A utility may be able to sell more or less electricity in a competitive market, however, and more complex TC determinations reflect this. Thus, the challenge becomes one of forecasting how utility sales may change over time. Coupled with this challenge is the probable regulatory desire to encourage utilities to reduce costs by increasing productivity and to increase revenue by pursuing surplus power markets. Regulators also do not want a utility to recover costs for uneconomical sales (i.e., when a utility's marginal generation costs exceed the market price). Joskow's approach puts utility shareholders at risk for recovery of all avoidable generation costs. Regulators need to be careful that they do not implement TC recovery and true-up mechanisms that turn out to provide the same incentives and disincentives to utilities as do traditional cost-of-service methods. Regulators should adopt true-up mechanisms that promote efficient behavior by the utility (e.g., using the performance-based approach suggested by Joskow).

No proposed true-up mechanism for TC recovery has yet been implemented. A proposal by the Vermont Public Service Board includes one or more trueups to capture the effects of utility cost-reduction efforts and to reflect changes in market prices. The Massachusetts Department of Public Utilities (1996) proposed to conduct true ups 2, 5, and 10 years after retail competition begins. FERC's Order 888 has no true up nor does the recent California legislation.

RECOVERY PERIOD

Regulators need to decide on the time period during which utilities will be allowed to collect TCs from their customers. A short recovery period (e.g., the 4-year period for utility-owned generation to be used in California) provides for a rapid resolution of these issues and a prompt transition to a fully competitive electricity industry. On the other hand, a recovery

period tied to the book and economic lifetimes of the underlying assets and liabilities matches cost recovery with cost incurrence. This type of approach might require TC payments for 20 or more years (e.g., until all power-purchase contracts have expired and all utility generating assets have been retired).

Another complication concerning the time period for TC recovery concerns the possible change from positive to negative TCs. As illustrated in Fig. 15, a utility's fixed generation costs are almost certain to decline from year to year (see Fig. 2 for a utility-specific example of this phenomenon). Competitive pressures may also lower variable costs over time. On the other hand, as electricity demand grows and uneconomical generating units are retired, market prices may increase. At some point (2005 in the illustration), the utility's losses will become gains. If the state regulator allows, say, an 8-year recovery period from 1996 through 2003, the utility will be allowed to recover all of its TCs. It will face unrecovered TCs in 2004, but will then enjoy *negative* TCs (i.e., increased earnings) in subsequent years until the assets and liabilities are retired.

Fig. 15. Hypothetical transition costs over time, showing substantial costs in the early years and gains (negative TCs) after 2004.

CONCLUSIONS

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 and state legislation and regulation, improving technologies, low natural-gas prices, and a widespread belief that competitive markets can better meet customer needs than regulated markets can.

Today's electricity industry is dominated by vertically integrated utilities, each of which enjoys a retail-monopoly franchise granted by the state. Tomorrow's industry may involve separate companies that generate, control, transmit, and distribute electricity and that offer retail electricity services. The generation sector may be competitive and, as a consequence, generation services may be free of much of today's economic regulation. The transition from one type of structure to another will, for some utilities, expose costs that cannot be sustained in competitive markets.

These transition costs are the potential monetary losses that utility shareholders or other parties might experience because of structural changes in the electricity industry. Roughly speaking, transition costs are based on the difference between regulated retail electricity prices for generation services and the competitive-market price of power.

The costs discussed here already exist and are, in general, being paid for by today's retail electricity consumers. Increasing competition exposes these costs to view, but does not create new costs. Legislators, regulators, and others need to address transition 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 allocation of these costs will cause serious problems, including extensive litigation, delays in the implementation of competitive markets, and de facto "deals" that favor economically and politically powerful interests (e.g., special discounts to large industrial customers).

Dealing with transition costs is, as the name implies, not an enduring issue. Once the transition from today's vertically integrated, regulated, monopoly industry to a more competitive industry is complete, this issue will disappear. However, the large dollar amounts at stake ensure that transition costs will be a critical issue for the next few years.

Transition costs can include four types of costs: assets, primarily expensive power plants and excess generating capacity; liabilities, primarily power-purchase contracts, fuel-supply contracts, and deferred income taxes; regulatory assets, whose value is based on regulatory

decisions rather than on market forces; and public-policy programs, including environmental compliance beyond that required by law, demand-side management programs paid for by all customers, and special programs for low-income customers. Unlike the first three categories, the costs in this last category are current, not sunk. That is, these costs could be discontinued if the programs were stopped.

Estimates of transition costs vary widely, with many falling in the range of \$100 billion to \$200 billion for the United States as a whole. By comparison, total shareholder equity in U.S. utilities is about \$190 billion. 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 (such as the Pacific Northwest) have almost no exposure to transition costs, while other regions (such as California and the Northeast) face substantial problems.

Legislators and regulators face five key questions concerning transition costs:

- What data, assumptions, and methods should be used to estimate the amounts of transition costs faced by each utility in a particular state?
- How much money is at issue for each utility in a particular state?
- What can the utilities, independent power producers and other wholesale providers, state regulators, and other parties do to reduce these dollar amounts?
- How should the remaining transition costs be shared among utility shareholders, different classes of customers (i.e., residential, commercial, industrial, and wholesale), wholesale producers, and state and federal taxpayers?
- What mechanism(s) should be used, and over what time period, to recover the remaining transition costs from these groups?

Utilities and regulators can use a variety of approaches to calculate transition costs. All approaches compare the regulated-market (i.e., book) values of utility assets and liabilities with their competitive-market values. San Diego Gas & Electric categorized these approaches 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 transition 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 the restructuring of the electricity industry is completed. The third dimension concerns the level of detail involved in the valuation, what is often called TD vs BU valuation.

Regulators might prefer TD methods because of their administrative simplicity and reliance on readily available data and computer models. Such methods are well suited for

problem identification and assessment (i.e., developing initial estimates of the magnitude of the transition-cost problem for a particular utility or state). However, in regulatory authorization for utility recovery of transition costs (i.e., determining the actual dollar amounts to be recovered), commissions might prefer the greater detail of BU 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 transition costs for different types of assets and liabilities.

Regardless of the method used to estimate the amount of transition costs, one must make certain assumptions. Although many factors affect the calculation of transition costs, only a few factors make a big difference. The most important factors affecting the magnitude of transition costs include future market prices of electricity, utility marginal costs of production, when RW begins, extent of RW, amount of utility regulatory assets, and utility fixed production costs. On the other hand, certain factors are likely to have very little effect on estimates of transition-cost amounts, including public-policy program costs, inflation rate, load growth, customer load factors, and T&D system loss factors.

Of the critical factors that affect transition 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 wheeling, although market forces may overwhelm regulation where large price disparities exist; and utilities can seek to cut their fixed and variable production costs. But wholesale prices—the most important factor—are largely independent of utility or PUC actions.

Strictly speaking, transition costs, because they reflect sunk (i.e., past) costs and future obligations, cannot be mitigated. However, regulators can allocate these costs among different groups. In some cases, regulators and utilities can find ways to cut operating costs and can then use these savings to offset what would otherwise be transition costs.

In other cases, regulators can only affect who bears the costs. Delaying wheeling protects utility shareholders at the expense of those retail customers who lack market power. Rapid and comprehensive implementation of retail wheeling could bankrupt some utilities unless the regulatory commission imposes what is often called a competition transition charge. This charge is collected from all users of the distribution system and is paid to utility shareholders.

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. Renegotiating power-purchase contracts can shift costs from ratepayers and utility shareholders to wholesale suppliers.

Finally, utilities can identify and implement ways to 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 transition costs with the remainder flowing to retail customers.

Because of the large dollar amounts, state and federal regulators are committing considerable time and attention to transition costs. The Federal Energy Regulatory Commission devoted almost 25% of its April 1996 landmark decision (Order 888) on open-access transmission to transition costs. Similarly, the California PUC recognized the critical role that transition costs play in restructuring the California electricity industry "to assure the continued financial integrity of California's investor-owned utilities" The California Legislature affirmed the Commission's support for utility recovery of transition costs.

The New Hampshire and Vermont regulators emphasized the role of utilities in mitigating transition costs. Both commissions plan to allow cost recovery only for those costs that remain after utilities have exhausted their mitigation opportunities. And both states adopted a broad view of mitigation, including actions that some might not consider mitigation, such as utility writeoffs of uneconomical assets or disallowance of costs associated with rates that are above the New England regional average.

Regulators and legislators must pay close attention to transition costs, primarily because of the large amounts involved in many states. Prompt resolution of transition-cost issues will hasten restructuring of the electricity industry, increase customer choice, and allow competitive forces to drive down costs and prices. Some of the transition-cost issues discussed here are analytical. But others are primarily policy issues. In particular, the allocation of transition costs among different stakeholders is a critical policy issue on which legislators and regulators will play a key role.

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APPENDIX

REFERENCE CASE

The base-case utility discussed in Chapters 6 and 7 owns seven generating units with a combined capacity rating of 4600 MW (Table A-1). In addition, the utility has two long-term power-purchase contracts that provide another 1600 MW of capacity. Thus, in 1995 the utility has a reserve margin of 34%. The utility's capacity factor of 42% (ratio of generation to potential generation) is less than the national average of 47%. The utility's generation operating costs vary from hour to hour, ranging from 1.0 to 4.6¢/kWh in 1995.

The utility can buy and sell on the spot market up to a maximum of 2500 MW (which represents the maximum capacity in either direction on the transmission system in that region). The 1995 spot price ranges from 1.7 to 5.5¢/kWh, depending on the time of year. Real wholesale prices remain constant from 1995 through 2000 and then increase at 3%/year thereafter. Weighted by consumption, the average spot price in 1995 is 2.5¢/kWh, above the utility's average marginal cost of 2.4¢/kWh.

Because spot prices are often above and occasionally below the utility's marginal cost of generation, the utility both buys and sells on the spot market. In 1995, the utility buys 500 GWh and sells 2700 GWh.

Table A-1. Characteristics of utility generation resources^a

	Hydro	Nu- clear	Coal 1	Coal 2	Gas CCCT	Gas CT 1	Gas CT 2	Con- tract 1	Con- tract 2
Capacity (MW)	500	800	950	750	700	400	500	600	1,000
Variable cost (¢/kWh)	0.6	1.0	2.1	1.7	2.7	4.6	3.6	3.3 ^b	3.0
Year book life ends ^c	2012	2009	2000	2016	2022	2012	2025	2002	2007
Year tax depreciation ends	1982	1994	1990	2006	2012	1997	2010	—	—

^aCCCT = combined-cycle combustion turbine; CT = combustion turbine.

^bThis contract is treated as a must-take unit.

^cFor the two contracts, these are the years that the contracts terminate. Because these units are not owned by the utility, neither book nor tax depreciation has any meaning.

In 1995, the initial year of the simulation, the utility's retail sales total 22,700 GWh, nearly one-third to the residential class and the remainder to the commercial/industrial class (Table A-2). The utility's peak demand is 4610 MW, and its overall load factor is 56%. With residential loads growing at 1.7%/year and commercial/industrial loads growing at 1.1%/year, total load grows at almost 1.4%/year, slightly faster than the 1.2% projected by the Energy Information Administration.

Because the cost of the must-take contract (3.3¢/kWh) is higher than the utility's marginal cost for most of the time, this contract increases the costs of producing electricity. Between 1995 and 2002 (the last year of this contract's life), production costs are 6% higher than they otherwise would be. Stated differently, if this contract could be treated as dispatchable, its capacity factor would be less than 3%; as a must-take unit, its capacity factor is 75%.

With an average retail rate of 9.64¢/kWh, the utility's total revenues in 1995 are \$2.04 billion. (Residential customers pay 11.60¢/kWh, and commercial/industrial customers pay 8.72¢/kWh that year.) Net income is \$179 million, which yields a return on equity (ROE) of 11.5% (slightly below the national average of 11.8% for the past three years). The utility's assets total \$4.95 billion that year, of which \$1.60 billion is in shareholder equity. The ratio of equity to assets (0.32) is the same as for the average U.S. investor-owned utility. The ratio of assets to revenue for this utility (2.6) is slightly higher than the 2.4 value for the average utility. And the ratio of net income to revenue of 0.09 is slightly lower than the national average of 0.10. The utility has \$800 million of regulatory assets in 1995; its ratio of regulatory assets to total assets (0.16) is higher than that for utilities overall (0.14). These differences are consistent with the situation for a utility that has a serious TC problem.

The utility's 1995 average price of 9.64¢/kWh includes 3.77¢/kWh for fixed production costs; 1.79¢/kWh for variable production costs; and 4.08¢/kWh for transmission, distribution, and other costs. This retail price is almost 40% higher than the average for U.S. utilities. Capital costs account for 49% of retail rates in 1995, compared with only 38% for U.S. utilities as a whole.

With inflation at 3%/year, modest load growth, no increases in real fuel prices, no new generating units coming online, and no additional investment in existing generating units, the utility's assets decline from \$4.95 billion in 1995 to \$3.07 billion in 2005 (in nominal dollars). The utility's reserve margin declines from 34% in 1995 to only 6% in 2005. In addition, all production costs, both O&M and fuel, remain constant in real dollars while loads grow during the analysis period. As a consequence of these factors, real retail rates decline from 9.64¢/kWh in 1995 to 6.89¢/kWh in 2005. EIA projects essentially no change in real electricity prices from 1995 through 2005. On the other hand, the California Energy Commission projects a 1% per year decline in real electricity prices from 1991 through 2013; the California utilities are among those with the largest TC problems. (All real dollar figures are in 1995 dollars.)

Table A-2. Summary information from ORFIN for the reference case

	1995	1996	1997	1998	1999	2000	2005
GENERATION SUMMARY							
Retail sales (GWh) at generator busbar	22,713	23,022	23,336	23,655	23,978	24,305	26,013
Wholesale (spot) sales (GWh)	2,700	2,590	2,388	2,195	2,011	1,833	579
Wholesale (spot) purchases (GWh)	-542	-633	-745	-871	-1,010	-1,159	-4,828
Net wholesale GWh	2,157	1,957	1,643	1,324	1,001	674	-4,249
Retail wheeling	0	0	0	0	0	0	0
Peak demand at busbar (MW)							
Retail	4,608	4,673	4,738	4,804	4,871	4,939	5,294
Wholesale sales	1,401	1,352	1,302	1,252	1,201	1,147	816
Wholesale purchases	219	241	263	287	311	336	888
Retail wheeling	0	0	0	0	0	0	0
Costs and prices (1995 ¢/kWh)							
Average retail price	9.64	9.50	9.17	8.86	8.56	8.17	6.89
Average production costs							
Fixed	3.77	3.80	3.55	3.31	3.08	2.76	1.86
Variable	1.79	1.79	1.80	1.81	1.82	1.83	1.80
Total	5.57	5.59	5.35	5.12	4.90	4.60	3.67
Average marginal cost of generation	2.35	2.38	2.41	2.44	2.48	2.50	3.18
Wholesale price to meet demand	2.51	2.51	2.51	2.51	2.51	2.51	2.91
Return on equity (%)	11.50	11.50	11.50	11.50	11.50	11.50	11.50
INCOME STATEMENT (million \$, nominal)							
Revenues	2,039	2,097	2,115	2,132	2,152	2,142	2,243
Expenses							
Fuel	245	256	264	272	280	288	368
Power-purchase contracts	241	246	252	257	263	268	98
Spot purchases	10	12	15	18	22	26	160
Spot sales	-74	-77	-73	-69	-66	-61	-29
Purchased power, total	177	182	193	206	219	233	229
O&M, fixed + variable	242	249	257	264	272	280	326
Production expenses, total	663	687	713	741	771	801	923
Nonproduction expenses	364	374	384	394	405	415	475
Book depreciation	221	232	234	235	236	207	215
Depreciation of regulatory asset	67	67	67	67	67	67	67
Revenue-sensitive taxes	143	147	148	149	151	150	157
Property taxes	78	80	80	77	74	71	61
Federal income taxes, current	136	136	130	130	128	115	100
Federal income taxes, deferred	-35	-34	-32	-36	-38	-28	-29
Expenses, total	1,636	1,688	1,723	1,757	1,793	1,799	1,968
Interest expense	224	229	219	209	199	190	149
Net income	179	180	173	166	160	154	126
BALANCE SHEET (million \$, nominal)							
Assets	4,949	4,735	4,523	4,312	4,104	3,927	3,074
Equity	1,600	1,538	1,475	1,417	1,361	1,310	1,072

The utility's fixed production costs are quite high in 1995, 3.77¢/kWh. However, these costs decline by 51% between 1995 and 2005 because of load growth, inflation, and depreciation of the utility's generating assets. Overall, depreciation accounts for 51% of the total decline in fixed production costs over this decade, load growth for 17%, and inflation for the remaining 32%. These "natural" declines in fixed costs reduce the TC burdens associated with RW.

RETAIL-WHEELING CASE

We assume that RW begins in 1996 with 5% of the residential customers and 10% of the commercial/industrial customers eligible for wheeling that year. These percentages increase linearly to 25 and 50% in the year 2000 and then remain constant through 2005.

Table A-3 shows the effects of wheeling on the utility when the utility keeps the sales at risk. In this case, the utility continues to sell electricity as a bundled product to the RW customers, but reduces its price to those customers to match what they could obtain on the wholesale market.

The numbers in Tables A-3 are the differences between the reference-case and RW-case values. Table A-3 has many zeros because, in this example, the utility retains the RW sales. Thus, its retail sales, wholesale sales, and operating costs are all identical to their reference values. The utility's RW revenues are lower because it sells some of the output of its generating resources at market value rather than at book value. This revenue reduction reduces taxes, net income, and ROE. (Retail prices increase slightly because more residential customers, with higher rates, remain retail customers than do commercial/industrial customers.)

The utility's loss increases from 1996 to 2000 as the amount of wheeling increases and reaches a maximum in the year 2000. From 2000 to 2005, the losses decrease for three reasons. First, we assume that wholesale prices increase at 3% per year beginning in 2001. Second, the must-take contract expires in 2002. Third, the utility's fixed cost of generation declines from year to year because of load growth and inflation. On an NPV basis, at the authorized ROE of 11.5%, the earnings loss if the utility keeps the sales is \$699 million, which represents 45% of utility equity as of 1995.

Table A-3. Differences between the reference and retail-wheeling cases if the utility keeps the sales (retail-wheeling results minus reference results)

	1996	1997	1998	1999	2000	2005
GENERATION SUMMARY						
Retail sales (GWh) at generator busbar	-1,934	-3,917	-5,953	-8,040	-10,180	-10,860
Wholesale (spot) sales (GWh)	0	0	0	0	0	0
Wholesale (spot) purchases (GWh)	0	0	0	0	0	0
Net wholesale GWh	0	0	0	0	0	0
Retail wheeling	1,934	3,917	5,953	8,040	10,180	10,860
Peak demand at busbar (MW)						
Retail	-379	-767	-1,166	-1,575	-1,995	-2,130
Wholesale sales	0	0	0	0	0	0
Wholesale purchases	0	0	0	0	0	0
Retail wheeling	379	767	1,166	1,575	1,995	2,130
Costs and prices (1995 ¢/kWh)						
Average retail price	0	0	0	0	0	0
Average production costs	0	0	0	0	0	0
Fixed	0	0	0	0	0	0
Variable	0	0	0	0	0	0
Total	0	0	0	0	0	0
Average marginal cost of generation	0	0	0	0	0	0
Wholesale price to meet demand	0	0	0	0	0	0
Return on equity (%)	-3	-6	-8	-11	-14	-9
INCOME STATEMENT (million \$, nominal)						
Revenues	-73	-142	-206	-266	-308	-171
Expenses						
Fuel	0	0	0	0	0	0
Power-purchase contracts	0	0	0	0	0	0
Spot purchases	0	0	0	0	0	0
Spot sales	0	0	0	0	0	0
Purchased power, total	0	0	0	0	0	0
O&M, fixed + variable	0	0	0	0	0	0
Production expenses, total	0	0	0	0	0	0
Nonproduction expenses	0	0	0	0	0	0
Book depreciation	0	0	0	0	0	0
Depreciation of regulatory asset	0	0	0	0	0	0
Revenue-sensitive taxes	-5	-10	-14	-19	-22	-12
Property taxes	0	0	0	0	0	0
Federal income taxes, current	-25	-48	-69	-89	-103	-57
Federal income taxes, deferred	0	0	0	0	0	0
Expenses, total	-30	-58	-84	-108	-125	-69
Interest expense	0	0	0	0	0	0
Net income	-44	-85	-123	-158	-183	-102
BALANCE SHEET (million \$, nominal)						
Assets	0	0	0	0	0	0
Equity	0	0	0	0	0	0

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