Restructuring the US electricity industry has become the nation's central energy issue for the 1990s. Restructuring proposals focus on more competitive market structures for generation and the integration of transmission within those structures. The proposed move to more competitive generation markets will expose utility costs that are above those experienced by alternative suppliers. Debate about these above-market, or transition, costs (e.g., their size, who will pay for them and how) has played a prominent role in restructuring proceedings. This paper presents results from a project to assess systematically strategies to address transition costs that will be exposed by restructuring the electricity industry.

La restructuration de l'industrie de l'électricité américaine est devenue la question au coeur des débats énergétiques du pays au cours des années 1990. Les propositions de restructuration portent principalement sur des structures de marché plus compétitives concernant la production d'électricité et l'intégration de la transmission au sein de ces structures. Le passage proposé à des marchés de production plus compétitifs révélera des coûts de service supérieurs à ceux rencontrés chez les fournisseurs parallèles. Ces coûts supérieurs au marché ou transitoires sont à l'origine d'un débat (portant entres autres sur leur dimension, qui les paiera et comment) qui a joué un rôle capital dans les procédures de restructuration. Cet article présente les résultats issus d'un projet d'évaluation systématique des stratégies visant à aborder les coûts de transition que la restructuration de l'industrie de l'électricité fera apparaître.

Assessing Transition-Cost Strategies: A Case Study

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Introduction

Transition costs are the potential monetary losses that electric-utility shareholders, ratepayers, or others might experience because of structural changes in the electricity industry. Transition costs are approximately equal to the difference between the embedded cost for generation services under traditional cost-of-service regulation and the competitive-market price for power. When government takes action to open current monopoly franchises to multiple generation providers and the competitive-market price falls below embedded generation costs, then transition costs will arise. Transition costs will include one or more of the following four classes of costs (Flaim, 1994):

- assets, primarily utility-owned power plants;
- liabilities, primarily long-term power-purchase and fuel-supply contracts;
- regulatory assets, including deferred expenses and costs that regulators allow utilities to place on their balance sheets; and
- public-policy programs, such as energy efficiency, low-income programs, and research and development.[1]

Uncertainty over the magnitude of poten-

1/ Unlike the first three categories, the costs in this last category are current, not sunk.

tial transition costs clearly contributes to the attention these costs receive in the ongoing restructuring debate. One of our earlier studies (Baxter and Hirst, 1995) identifies industry-wide estimates that range from $20 billion to $500 billion. Our study confirms that potential transition costs can differ widely, depending on assumptions about future market prices, the portion of retail load that obtains market prices, and the timing and pace of restructuring. We develop national estimates for investor-owned utilities that ranged from $16 billion to $268 billion and suggest that the most plausible range for potential transition costs is $72 billion to $104 billion.[2]

Other national studies report somewhat larger estimates of potential transition costs. The most recent study by Moody's (Hackett, Cohen, and Abbott, 1996) presents a national estimate of $133 billion for investor-owned utilities. Resource Data International (RDI, 1996) reports industry-wide transition costs at $184 billion. The RDI estimate includes publicly-owned utilities and cooperatives, which explains a large part of the difference with Moody's estimate. RDI's estimate for investor-owned utilities is $134 billion. Our estimates differ from RDI's and Moody's primarily because of the treatment of income taxes. Our estimates are net of the change in income taxes.[3] These national studies suggest that potential transition costs are substantial, though smaller than many earlier estimates.

As the restructuring debate in the electricity industry continues, the question of how to address transition costs remains a major impediment to more rapid progress on several other issues, including market structure, customer access and choice, and regulatory jurisdiction. Regulators, policy analysts, utilities, and consumer groups have proposed a number of strategies to address transition costs. Suggested strategies range from immediately opening retail electricity markets (and letting utility shareholders bear all transition costs) to delaying retail competition (and assigning the preponderance of costs to ratepayers).

Despite the role of transition costs in the larger restructuring debate, a critical missing element is information about how specific strategies will affect these costs. Little systematic analysis of different transition-cost strategies is publicly available. Only with this information in hand, will policy makers and stakeholders be able to identify the more promising strategies and craft approaches that avoid "winner-take-all" outcomes.

The paper's first section describes a framework for assessing transition-cost strategies and the development of a base-case utility and retail-wheeling scenario. The second section identifies and assesses different transition-cost strategies, presenting each strategy's effect on transition costs for utility shareholders. The paper concludes with a summary and recommendations.

Approach

We use an integrated utility planning model (the Oak Ridge Financial Model (ORFIN)) to assess the effects of different strategies on transition costs (Hadley, 1996). The model simulates a single utility interacting with an unbundled generation market. The utility serves bundled retail customers through its integrated generation, transmission, and distribution system. The utility also buys and sells power on the generation market when economical, subject to certain system constraints, such as the utility's wholesale transmission capacity. Wheeling customers purchase electricity directly from the generation market but receive electricity through the utility's transmission and distribution (T&D) network. The model includes a production-costing module (to simulate the operation of the utility's generation resources and their interaction with an unbundled generation market), utility financial statements (to link utility operations to the firm's income and balance statements), and a rate-design module (to attribute costs to generation, transmission, distribution, and general

2/ Unless otherwise noted, we express all cost or price estimates in 1994 US dollars.

3/ For every dollar of lost revenue contributing to transition costs, the loss to utility shareholders is one dollar minus the utility's tax rate. See Baxter and Hirst (1995) for a detailed illustration of the effects of income taxes on transition-cost estimates.

services, and to assign costs to different customer classes).

In assessing most strategies, we follow three steps. First, we create a base-case utility. Second, we develop a retail-wheeling scenario and estimate the financial consequences relative to the base case. We hold retail prices constant from the base case so that utility shareholders bear the transition costs.[4] The base-case utility under the retail-wheeling scenario is the reference point for our assessment. Third, we incorporate a specific strategy into the planning model and estimate the resulting financial consequences to utility shareholders. Our estimate of each strategy's effect is the difference in transition costs between the retail wheeling scenario with and without the strategy.

ORFIN's income statement reflects the annual results of the utility's operations. The income statement includes detail about revenues, expenses, and income. Net income is the difference between revenues and expenses. Revenues are the product of electricity sales and prices, summed over the relevant customer classes. Operating expenses include production and nonproduction costs, book depreciation, taxes, and interest payments. Production costs include fuel and operations and maintenance (O&M) costs for the utility's power plants, power-purchase-contract costs, and purchases and sales on the generation market. ORFIN yields what is called a bottom-up ex ante administrative valuation of transition costs (Baxter, 1995). The annual transition costs are the annual difference in net income between the base case and the retail-wheeling scenario. The total transition costs are the sum of these annual differences, discounted to present value dollars:

4/ We ran the base case using annual rate cases with a future test year to ensure that the utility earns its authorized return on equity each year of the analysis period. The retail and wheeling prices so determined are then used in the retail-wheeling scenario. Differences in annual earnings between the base-case and retail-wheeling scenarios are the model's estimates of transition costs (see below). Keeping prices fixed between the base-case and retail-wheeling scenarios ensures that none of the transition costs are borne by retail customers; all are borne by utility shareholders.

$$Net\ Income_t = Revenues_t - Expenses_t$$

$$Transition\ costs\ = \sum_{t=1}^{T}[(Net\ income_{bc,t} - Net\ Income_{rw,t}) \div (1+d)^t]$$

We calculate transition costs as net present value at the utility's return on equity for the years t =1 through year T. In our analysis, the utility's nominal return on equity is 11%, which, when combined with a 3% inflation rate, yields a real discount rate, d, of 8%. We also set T =10 for most strategies. Determining an appropriate value for T can be difficult because, under certain circumstances, the annual values calculated with the second equation may be positive for a few years and then turn negative. Increasing prices and declining costs may eventually result in utility total generating costs that are below market prices. Thus, an important question for decisions about transition-cost estimation and recovery is whether any projected future profit margins over an asset's economic life should be credited against nearer-term losses. $Net\ Income_{bc,t}$ is from the base case for year t while $Net\ Income_{rw,t}$ is from the retail-wheeling case for the same year. Our technical report offers additional details on the assessment framework, modeling approach, key assumptions, and results (Baxter, Hadley, and Hirst, 1996).

The Base-Case Utility

The base-case utility is developed using actual utility data from 1993 and 1994. We select a utility that faces potentially substantial transition costs arising from three of the major transition-cost categories: utility-owned generation, power-purchase contracts, and regulatory assets (Baxter, 1995). The actual utility data are from an industry-wide data base (RDI, 1995), the utility's annual reports and resource plan, and the utility's Section 10-K filings with the Securities and Exchange Commission. In our base case and subsequent analyses, our objective is to ground our analysis with actual data whenever possible to make our assessments more concrete.[5]

5/ To preserve the anonymity of the utility used for

As of 1995, the base-case utility is investor-owned with a rate base of $7.27 billion, common equity of $3.20 billion, and revenues of $4.62 billion. Annual retail sales are 43,800 GWh, and retail peak demand is 7500 MW. In the absence of retail wheeling, the utility forecasts annual electricity sales and peak demand to grow at about 1.0%/year. The utility's system load factor is 66%.

The utility's total generating capacity is 10,000 MW. The utility owns about 52% of this capacity. The remaining capacity consists of long-term power-purchase contracts. All the long-term contracts are in effect through the 10-year analysis period. Roughly two-thirds of these long-term contracts (approximately 3100 MW) are with qualifying facilities (QFs). Nearly 90% of the QF contracts (2700 MW) have "must-take" provisions; that is, the utility must purchase power from these facilities when they are available. The combined capacity and energy payments for these must-take contracts result in purchased electricity at about 7.2¢/kWh. The utility's large coal plant (1570 MW), one of its natural gas plants, and all of its hydro plants (725 MW) are fully depreciated. The utility's nuclear plant (1270 MW) is a comparatively recent addition to the utility's rate base and will not be fully depreciated until 2018. The utility's regulatory-asset-account balance totals about $1 billion in 1995.

Because the utility has surplus capacity, substantial transmission links (3600 MW) with neighboring systems, and low marginal generation costs (an average of about 2.1¢/kWh), the utility is active on the unbundled generation power market. The utility sells about 9400 GWh into the unbundled market and purchases about 1000 GWh. Unbundled generation sales decline about 4%/year, and purchases increase about 9%/year as the utility's retail sales increase over time.

We characterize the unbundled generation market using four price blocks.[6] Purchases from the four blocks are available 30%, 30%, 35%, and 5% of the time, respectively. The purchase prices from the blocks are 2.0¢/kWh, 2.2¢/kWh, 2.4¢/kWh, and 6.0¢/kWh, respectively. We assume that generation sale prices are 0.1¢/kWh lower than the purchase prices for each block because the utility has to pay for losses or other ancillary services when selling power on the market. We assume the base-case utility is a price-taker in this market, and that its purchases from and sales to this larger market have no effect on market prices.

In estimating rates for the base case, we ensure that the utility collects revenues sufficient to recover all costs, including the utility's authorized 11% return on equity. Full-service retail customers face these same rates in the retail-wheeling scenario. In 1994, the utility's average retail rate is substantially higher than the national average for electric utilities (11.1 vs 6.9¢/kWh), as are total production costs (5.7 vs 4.5¢/kWh) (Energy Information Administration, 1995). Most importantly for potential transition costs, the utility's average total production cost is well above the average unbundled generation price (2.5¢/kWh, weighted by consumption). We also assume modest inflation (3%/year), no real increases in fuel prices, no new generating units under construction, no additional investments in existing generating units, but new investments in transmission ($86 million/year) and distribution ($164 million/year).

The Retail-Wheeling Scenario

We assume retail wheeling begins in 1996 for commercial and industrial customers, and in 1997 for residential customers. By 1998, 60% of commercial and industrial customers have alternative suppliers, as have 40% of residential customers by the year 2000. These percentages also apply to new customers entering the utility's former service area. These assumptions about the timing and pace of wheeling are developed exogenously, and then incorporated in ORFIN.

Under the retail-wheeling scenario, utility

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this case study, we multiply key utility-specific data by a scalar to create the base case.

6/ We did not explicitly treat the structure and operation of this unbundled generation market. We simply assume that, subject to transmission constraints and losses, a fully competitive generation market exists.

retail sales drop by 24,700 GWh in the year 2000. The utility quickly eliminates generation purchases, but dramatically increases sales to the unbundled generation market. By the year 2000, the utility has increased sales about 0.9 kWh on the market for every 1.0 kWh in lost retail sales.

The utility's loss of net income is $137 million in 1996 and peaks at $527 million in 2000, as the amount of wheeling increases, before declining gradually to $510 million by 2005 (in nominal terms). The losses decrease from 2000 to 2005 because the utility's fixed generation costs decline each year due to inflation and depreciation of generation assets. The total transition costs are $2.45 billion under the retail-wheeling scenario (1996–2005, net present value), which represents 77% of the utility's equity as of 1995.

Transition-Cost Strategies Assessed

We compile a list of available strategies from filings at federal and state proceedings, published literature, industry press, and consultant reports. We group the many individual strategies into four major categories, listed below. Under each major category we identify the individual strategies assessed in the next section.

Market actions affect the market structure for electricity or rely on market mechanisms:
- rapidly open retail markets;
- delay the onset of retail wheeling;
- increase system load factor (reduce retail demand or increase retail sales); and
- sell energy freed by departing retail customers.

Depreciation options modify the depreciation of utility assets:
- accelerate depreciation of generation plant;
- accelerate depreciation of generation plant and decelerate depreciation of T&D plant; and
- accelerate depreciation of regulatory assets.

Rate-making actions change the rates utilities charge for electricity service:
- charge departing customers for ancillary services; and
- charge exit fees for departing customers.

Utility cost reductions offset transition costs or lower electricity prices:
- reduce operating costs;
- reduce public-policy program costs; and
- reduce power-purchase costs.

Several of the strategies we examine reduce utility operating costs. To avoid making arbitrary assumptions about the potential for cost reductions, we establish performance benchmarks for each aspect of utility operations examined. Our objective is to estimate benchmarks that represent excellent cost performance for the electric-utility industry. We select cost performance at about the 90th percentile as our benchmark for each cost variable. That is, our definition of excellent performance is that only about 10% of the firms in the industry have equal or lower costs for a specific aspect of utility operations (see the Appendix for more details).

Assessment Results

In this section, we present results of different strategies that rely on either market actions, depreciation options, rate-making actions, or utility cost reductions. Using the assessment approach described in the previous section, we examine individual strategies within each major category. When strategies (*e.g.*, increasing load factors) can be represented in more than one way (*e.g.*, reducing peak demand with no change in annual sales or increasing annual sales with no change in peak demand), we examine the important alternatives. In the concluding section, we make general comparisons of results across strategies.

We present the results graphically for two reasons. First, graphs are easier to grasp than are tabular displays. We use the same scale on the graphs to ease comparison among charts. Second, the exact numerical results matter far less than do the overall trends and magnitudes. Indeed, the exact numbers depend on the specific assumptions that define the base-case utility and retail-wheeling scenario.

Market Actions

Results from our assessment of six strategies

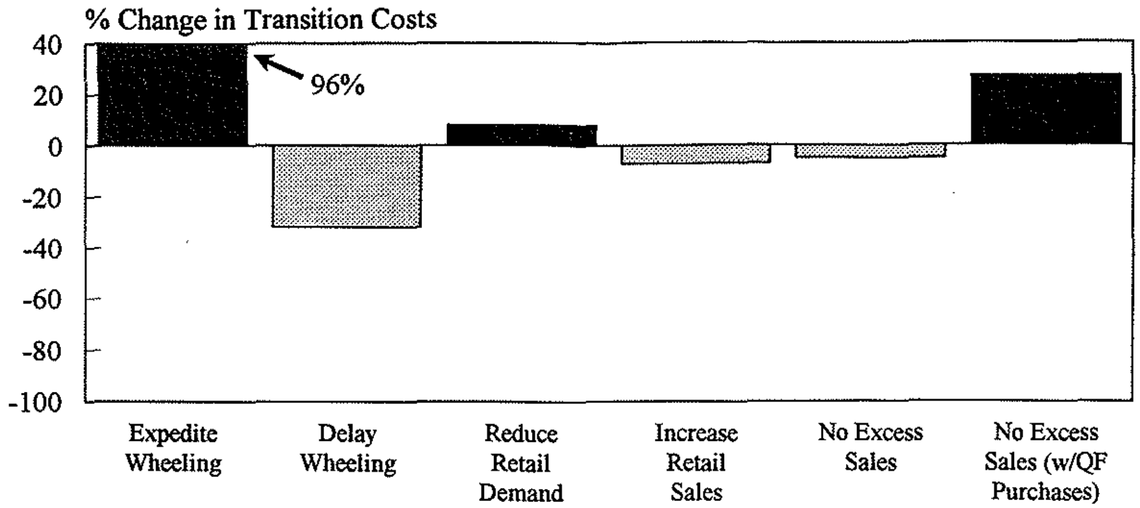

Figure 1: Effects of Market Actions on Utility Transition Costs

are displayed in Figure 1. Because this section contains several figures like Figure 1, we want to be clear about their contents. The y-axis displays changes in transition costs for utility shareholders as a result of introducing a strategy, identified along the x-axis, to the retail-wheeling scenario. Thus, Figure 1 presents results relative to the transition costs experienced by the base-case utility under the retail-wheeling scenario. A positive estimate means the strategy increased shareholders' transition costs relative to the retail-wheeling scenario; a negative estimate indicates the strategy decreased transition costs. A delay in wheeling, for example, results in transition costs to utility shareholders of $1.66 billion, which is $790 million (32%) less than the $2.45 billion in transition costs from the retail-wheeling scenario.

A strategy of rapidly opening retail electricity markets is represented by the retail-wheeling scenario we described above. If we assume a more rapid scenario, for example, one in which virtually all retail customers wheel by the year 2000, then the utility's transition costs increase 96% ($4.80 billion, or $2.35 billion more than the retail-wheeling scenario). The $4.80 billion estimate also approximates the transition costs electricity consumers bear, assuming that customers do not get access to competitive electricity markets and the utility fails to reduce costs. The $4.80 billion estimate defines the extreme effects of both rapidly opening retail electricity markets and keeping these markets closed for an extended period.

These extreme strategies bracket the range of possible outcomes from market actions, but a strategy to delay wheeling is unlikely to have as its objective an indefinite or lengthy delay. As a result, we examine a strategy where retail wheeling occurs, but the start and pace differ from our retail-wheeling scenario. Compared to the retail-wheeling scenario, we delay the onset of wheeling for each customer group by two years and assume the time needed to reach the maximum wheeling level is twice as long as in the retail-wheeling scenario. The strategy to delay wheeling reduces transition costs to shareholders by about 32% ($790 million), compared to the retail-wheeling scenario, for two reasons. First, the utility delays the financial consequences of retail wheeling by two years. Second, because the pace of wheeling is slower, the utility is able to recover a greater share of sunk generation costs from retail customers.

Analysts have identified improving system load factors as one possible objective of utility mergers. Other possible objectives are reducing costs, which we discuss later, and enhancing the value of each utility's asset portfolio. Setting aside the question of whether a utility will be able to manage loads effectively in a competitive environment, we assume the utility achieves a 5% improvement in system load factor (*i.e.*, from 66% to 69%). The utility can increase its load factor either by reducing retail demand at peak periods, or by increasing retail sales during off-peak periods. We expect an increase in load factor through peak demand reductions to lower utility expenses, which it does. Unfortunately, utility revenues decrease more than expenses because improving the system load factor reduces revenues collected from customer demand charges. The net result is an increase in transition costs of 8% ($210 million). When a utility successfully increases its system load factor through reduced demand, this result suggests a need to revise the allocation between fixed and variable charges to avoid reduced earnings. Under the alternative strategy, increasing off-peak sales, utility expenses increase, but revenues increase more. The net result is a decrease in utility transition costs of 7% ($160 million).

The assessment framework incorporates the effects of marketing the energy freed by departing customers. Thus, the transition costs of $2.45 billion from the retail-wheeling scenario already reflect any benefits and costs derived from increased unbundled generation sales. To estimate these effects, therefore, we limit the utility's annual unbundled generation sales in the retail-wheeling scenario to the same level as in the base case without retail wheeling. In this revised version of the retail-wheeling scenario, the utility is unable to convert any of its lost retail sales to unbundled generation sales. The unexpected result is a 4% reduction ($110 million) in utility transition costs. Under the intial retail-wheeling scenario, the utility sells a portion of its purchases from the must-take contracts at a loss on the unbundled generation market. This occurs when QF purchases exceed demand from the utility's bundled retail customers. When we limit the utility's sales to the generation market under the revised wheeling scenario, ORFIN responds by reducing required purchases from the must-take QF contracts. The resulting production-cost savings are substantial.

We examine a second case where all the utility resources except the QF must-take contracts operate at the same level as above (*i.e.*, the case where the utility has the same level of unbundled generation sales in the retail-wheeling scenario as in the base case). This second case examines the implications if the utility suffers a loss of retail sales, but must purchase from the QF must-take facilities whenever they are available. In this case, transition costs increase by 27% ($660 million) because the utility purchases some above-market QF power and sells it at a loss on the unbundled generation market. Results from these two cases suggest that generalizing about the effects of marketing energy freed by departing retail customers is difficult; the benefits (or costs) of marketing excess energy will be utility-specific.

Depreciation Options

In the base-case utility, three of six utility-owned generating plants are not fully depreciated by 1996. Of these three plants, only the nuclear plant carries a substantial depreciation expense ($115 million/year). We placed the nuclear plant in the rate base in 1988; the plant will be fully depreciated by 2018. The utility's revised depreciation strategy is to retire the plant's construction debt in the year 2000 by accelerating depreciation payments beginning in 1995. The result of this strategy is higher transition costs for shareholders from 1996 to 2000, but then lower transition costs beyond 2000. The net effect of accelerated depreciation is to increase transition costs by 5% or $120 million (Figure 2).

Another strategy is to offset the increased costs of accelerated depreciation by decelerating depreciation of other assets. In the base case, the average depreciation expense for T&D is about $99 million/year (between 1996 and 2005), and the depreciation schedule is 50 years for new capital additions. To assess this strategy, we lengthen the depreciation schedule of T&D assets by 25 years (from 50 to 75 years). Extending T&D depreciation by 25 years increases transition costs about 2% or

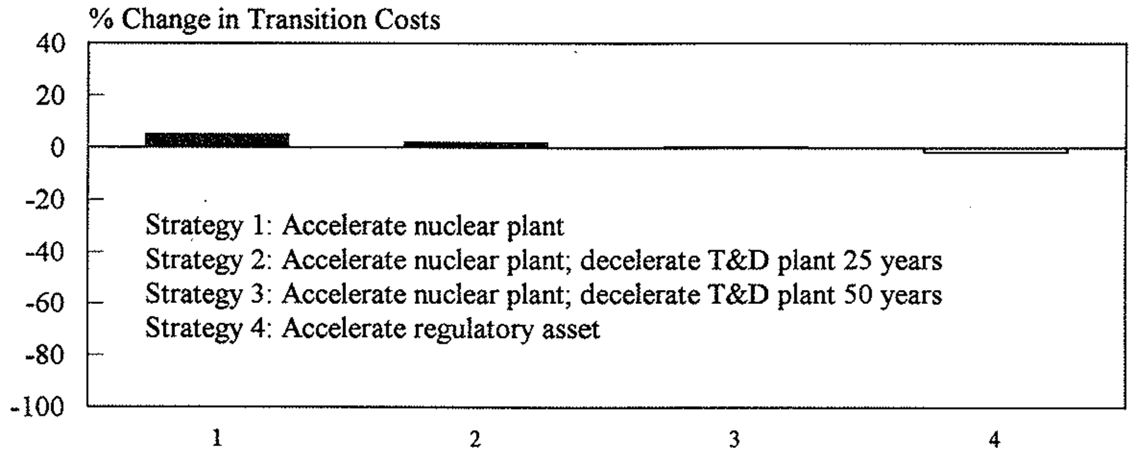

Figure 2: Effects of Depreciation on Utility Transition Costs

$50 million (*i.e.*, transition costs decrease about 3 percentage points or $70 million relative to the accelerated depreciation strategy). Extending depreciation of T&D assets by 50 years virtually offsets the increased cost from accelerating depreciation of the nuclear plant. Even this latter strategy leaves the utility with transition costs of almost $2.5 billion. But the assessment indicates the utility can alter depreciation schedules to make itself no worse off than it was under the retail-wheeling scenario while retiring its largest generation-related debt expense. This strategy shifts costs from the unregulated generation enterprise to the regulated T&D entity.

Finally, the utility also has a regulatory-asset-account balance of $1 billion in 1995 that is fully depreciated by 2005. The utility's revised strategy is to fully depreciate the regulatory asset by the end of 1997 by accelerating depreciation payments beginning in 1995. The net effect of this strategy is to decrease transition costs by almost 2% ($40 million). The higher costs from 1996 to 1997 are more than offset by the lower costs beyond 1997. Should the utility wait to accelerate depreciation until retail wheeling begins in 1996, its transition costs increase by 3% ($80 million).

Rate-Making Actions

Unbundling rates is one probable outcome of industry restructuring. For unbundling, we examine a strategy in which the utility charges retail-wheeling customers for ancillary services. In a study to assess ancillary service costs at 12 US electric utilities, researchers found the average total cost to be about 0.4¢/kWh, of which about 0.3¢/kWh are fixed costs (Kirby and Hirst, 1996). We implement this ancillary-services charge as an increase of $20/kW-year in the wheeling demand charge. Charging for ancillary services reduces utility transition costs by 10% ($240 million).

Exit fees assign transition costs to departing customers. An exit fee is one transition-cost strategy the Federal Energy Regulatory Commission (1996) establishes for certain departing wholesale customers. As a first step, we estimate a one-time exit fee for the two customer classes in the base-case utility and assume customers pay the fee the year they first take wheeling service. We use the following formula to calculate the one-time exit fee for each departing customer cohort by customer class:

$$Exit\ Fee_{c,r} = [\ \underset{n=c}{\overset{n=2018}{NPV}}\ (total\ generation\ cost_n - market\ price_n + regulatory\ asset\ cost_n)] \times average\ electricity\ use_{r,1994}$$

The exit fee for year c and customer class r ($Exit\ Fee_{c,r}$) is the net present value, beginning in year c, of the difference between total generation costs, including regulatory asset costs, and the market price of generation. *Total generation cost$_n$* is the utility's fixed and variable generation costs in year n. *Market price$_n$* is the average unbundled generation market price in year n. *Regulatory asset cost$_n$* is the depreciation expense in year n for the regulatory asset account balance in 1994. *Average electricity use$_{r, 1994}$* is the average use in 1994 for customer class r.

We note several important elements of this simple formula. First, we calculate an exit fee for customers departing in 1996, 1997, 1998, and so on; that is, for each cohort of customers leaving the utility. Second, while the time period for each cohort's calculation differs, the endpoint, the year 2018, is the same. We select 2018 as the common endpoint because that is the year the utility's last debt obligation (the nuclear plant) undertaken prior to restructuring is finally retired. Finally, we use the average electricity use in 1994 for each customer class as a proxy for the expected future electricity use. Note that this assumption will lead to a slight underestimation of the utility's expected future revenue stream from these departing customers because one of our base-case assumptions is for a slight positive growth in electricity use per customer.

In addition, we use two approaches to estimating the difference between the utility's total generation costs and the market price. The first approach estimates this difference for a single year (*i.e.*, the year the customer departs), and then holds this difference constant over time. The second approach, reflected in part by the above formula, accounts for how the difference between utility costs and the market price might change over time. Our analysis assumes no change in fuel prices or market prices over time. These assumptions greatly ease our interpretation of the effects of different transition-cost strategies. We do forecast declines in fixed generation costs to reflect the depreciation of generation assets over time. As a result, total utility generation costs decline over time as generation assets are depreciated.

As Table 1 shows, exit fees calculated with the first approach (total generation costs held constant) are more than 50% higher than those calculated with the second approach (changing generation costs). Exit fees also decline over time, and the first cohort departing pays the highest fee. Exit fees decline because each succeeding cohort has fewer years of transition costs rolled into the fee. More importantly, the difference between the utility's generation costs and the market price is greatest in 1996 and then declines each year because of depreciation. Customers that depart early must pay for this greater difference between utility costs and market prices. The higher exit fees reduce the utility's transition costs by 146% (Figure 3), which eliminates the utility's transition costs and results in a gain of $1.14 billion in net income from 1996 to 2005. The lower exit fees eliminate 96% of the utility's transition costs ($2.36 billion). In principle, the lower exit fee should eliminate all utility transition costs; but as we noted above, our use of a proxy underestimates projected electricity use for departing customers.

We find that holding constant the first-year price difference between embedded generation costs and market prices will overestimate an exit fee intended to recover historical obligations the utility incurred on behalf of departing customers. While our assessment does not account for changes in fuel prices and market prices of electricity over time, it does account for a change that utility planners and financial analysts can easily calculate – the reduction in utility fixed costs as assets depreciate over time.

Utility Cost Reductions

Differences in generation costs between regions has focused attention on the potential for cost reductions in generation services. Analysts and commentators have paid less attention to the cost-reduction potential for non-generation services. We do not posit the mechanism(s) that could be designed to encourage these reductions. The electricity industry widely discusses performance-based regulation as one possible mechanism to encourage utilities to reduce costs over time (*e.g.*, Comnes, 1995). The transition-cost-recovery process itself could also provide utilities an

Table 1: One-Time Exit Fees for Successive Cohorts of Departing Customers (1994 $)

	1996	1997	1998	1999	2000
Residential customers					
Constant generation costs		2,331	2,171	2,017	1,872
Changing generation costs		1,500	1,400	1,303	1,209
Commercial & industrial customers					
Constant generation costs	53,059	49,393	45,898		
Changing generation costs	34,046	31,780	29,598		

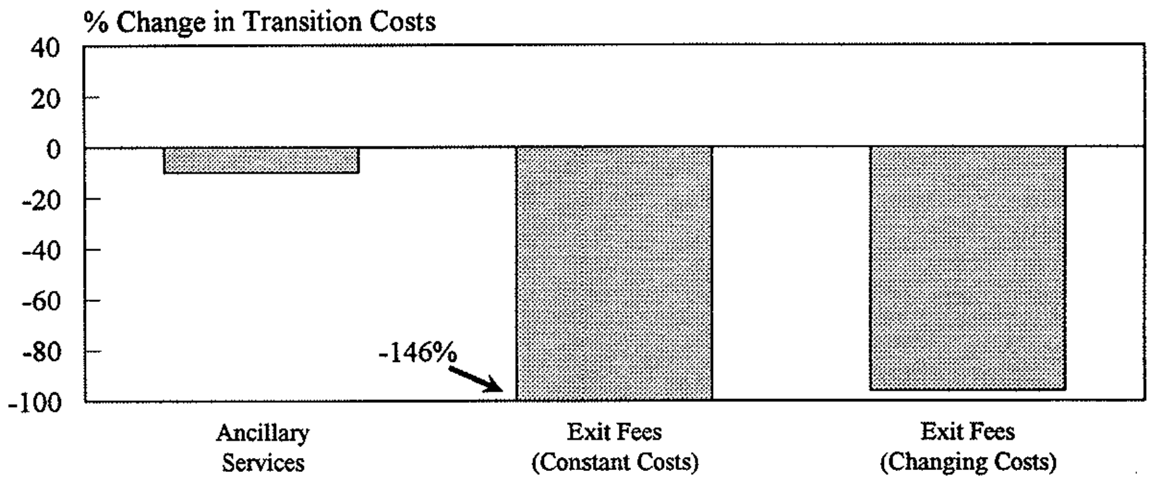

Figure 3: Effects of Rate-Making Actions on Utility Transition Costs

incentive to reduce costs if a meaningful portion of these reductions is used to offset transition costs.

Figure 4 indicates the potential effects on transition costs of reductions in five nongeneration costs. The first four cost variables compare base-case utility performance to a performance benchmark. Achieving benchmark performance in customer service reduces utility transition costs by 16% (almost $400 million). For administrative and general (A&G) costs, the cost-reduction potential is 43% (more than $1 billion). Transmission O&M exhibits a cost-reduction potential of about 8% ($190 million), while achieving benchmark performance for distribution O&M reduces costs 10% ($250 million). These four cost variables suggest that the base-case utility has comparatively high costs in areas other than generation. Cost reductions in these four nongeneration areas have potentially large effects on utility transition costs and economic efficiency.

Public-policy-program costs are the fifth nongeneration cost variable in Figure 4. Our estimate of cost reductions here is not based on a performance benchmark. Instead, we assume that the utility reduces program expenditures by 75%, from $30 million/year to about $7 million/year. We also assume that this budget cut is accompanied by reductions in services or benefits. As a result, we redefine the base-case utility to reflect the 75% budget cut and we reestimate retail rates before introducing the retail-wheeling scenario. The ensuing reduction in transition costs is small because the base-case utility spends only about 1% of its revenues on public-policy programs – a $23 million cut in public-policy programs reduces utility transition costs by $23 million. Because cuts in public-policy programs lead to equivalent reductions in utility transition costs, some members of the electricity policy community are concerned about the effects competitive pressures will have on public-policy-program expenditures in the absence of legislative or regulatory action.

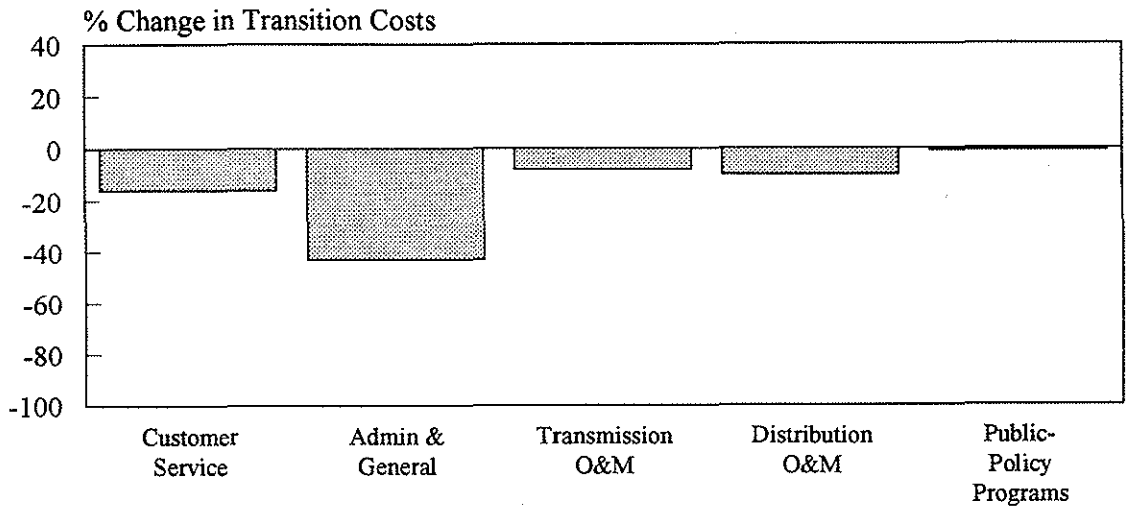

Figure 4: Effects of Nongeneration Cost Reductions on Utility Transition Costs

Figure 5 presents results of the utility's achieving performance benchmarks for generation-plant O&M. Results for each plant are standardized by generating capacity. Reducing O&M costs for the nuclear and coal plants has by far the greatest potential to offset transition costs. Reaching the performance benchmark lowers transition costs by 19% ($470 million). The O&M cost-reduction potential for the remaining plants is small.

Of course, certain O&M cost reductions will themselves require investments by the utility, perhaps in training personnel, improving parts quality, or devising and implementing new procedures. The utility must decide which investments provide the highest return. In a competitive environment, for example, reducing the O&M costs on a plant whose marginal costs are well above market prices is not productive. Reducing variable O&M costs will not increase the operation of many plants because these costs are typically a small fraction of their total variable costs, which are the basis for economic dispatch. In contrast, steps to reduce a plant's heat rate may enhance its competitive position. Another effective strategy is to reduce O&M costs for plants with marginal costs that already beat the market. For these plants, cost reductions increase the margin earned with each kWh generated; in our analyses, this is the case for both the nuclear and coal plants.

The base-case utility spends more than $1.2 billion/year on power purchases. Virtually all these power-purchase costs are incurred by the utility's 2700 MW of "must-take" QF contracts. The utility's energy payments to the must-take QFs are about $1 billion/year, with the balance being capacity payments.

We examine four strategies to reduce the utility's power-purchase costs (Figure 6). The first strategy we assess is to discount the capacity payments of $77/kW-year the utility makes to all QFs, not just the must-take facilities. This strategy discounts these payments to the market price for capacity. We construct a national average capacity price using the 10-year average market prices estimated by Moody's for each North American Electricity Reliability Council region (Fremont, 1995). Our estimated market price is $40/kW-year. With capacity payments at $40/kW-year, the utility reduces transition costs by 17% (more than $400 million).

The second strategy also discounts current capacity payments to market, but the utility accelerates these payments. By shortening the payment schedule, the utility must increase capacity payments to $76/kW-year in 1995 and make these higher payments through the

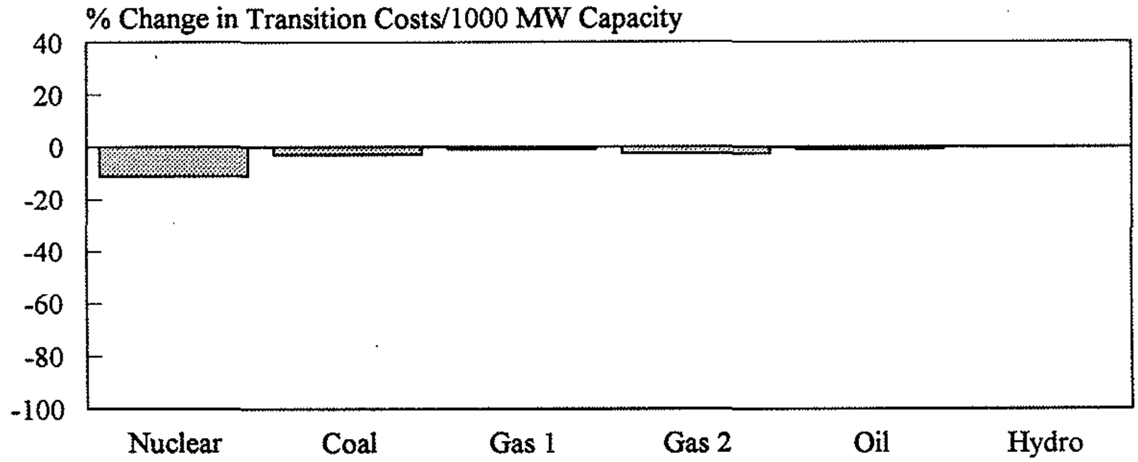

Figure 5: Effects of Generation O&M Cost Reduction on Utility Transition Costs

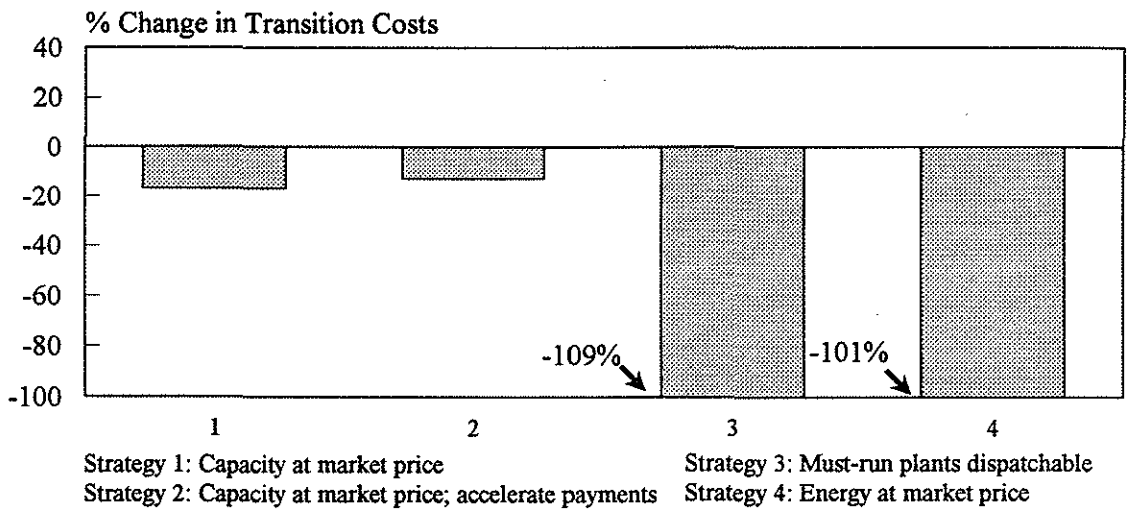

Figure 6: Effects of Power-Purchase Cost Reductions on Utility Transition Costs

year 2000. The resulting cost increases through 2000 are more than offset by the subsequent cost reductions; the net result is a transition cost reduction of 13% (more than $300 million).

In the third strategy, the utility continues to make the contracted capacity payments (at $77/kW-year), but successfully negotiates full dispatchability provisions for all the must-take facilities. These facilities continue to set their energy price at 6¢/kWh. Not surprisingly, the utility rarely calls on these facilities, and the QF capacity factors approach zero by 1998 in this strategy (down from 70% in the retail-wheeling scenario). The result is a reduction in utility transition costs of 109% (almost $2.70 billion; that is, transition costs are eliminated, and the utility's net income increases by about $200 million compared to the base case).

The fourth strategy maintains the must-take contract provisions but discounts the energy payments to the average market price of 2.5¢/kWh. Power-purchase contract costs decrease substantially and, as a result, the utility's transition costs are eliminated.

From the above analysis, we see that the strategies that discount energy payments to market prices (strategies 3 and 4) produce large cost reductions. These reductions can exceed the utility's total transition costs. Of course, these reductions actually represent shifts in costs from utility shareholders to QF shareholders, which QF shareholders will resist. QFs will have incentives to renegotiate contracts when maintaining the full provisions of the existing contracts threatens the financial survival of the utility. In addition, provisions of certain existing QF contracts may become incentives to renegotiate once a competitive generation market is established. For example, consider a contract term that states that a QF must operate to receive its fixed energy payments. If the prevailing market prices are below the QF's operating costs, then the QF may have to operate the plant at a loss to receive its fixed payment. The QF will clearly seek to renegotiate its contract if this loss exceeds the value of the fixed payment. Similarly, a QF with energy payments tied to short-run avoided costs, as established by a competitive generation market, will be motivated to renegotiate if its operating costs exceed market prices. Finally, depending on their debt costs and discount rates, some QFs 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.

Conclusions and Recommendations

Table 2 groups the different strategies we assess by their potential effects on the base-case utility's transition costs. Because the absolute effects of different strategies are linked to the assumptions that define our base-case utility, this table provides a more general indication of how a strategy may affect other utilities. When reviewing Table 2, keep in mind that utilities potentially at risk of incurring transition costs are not representative of all US utilities. Those utilities at risk will have substantial above-market costs in at least one of three major classes of generation-related costs: utility-owned generation, long-term purchase obligations, or regulatory assets.

Strategies with potentially large effects change transition costs to utility shareholders by 25% or more. For at-risk utilities, delaying retail wheeling (Figure 1),[7] charging exit fees to departing customers (Figure 3), and discounting energy payments to QFs to market prices (Figure 6) are all likely to result in large reductions in utility transition costs. Rapidly opening retail markets (Figure 1) leads to large increases in transition costs for at-risk utilities. The effects of the utility's failure to market the energy freed by departing retail customers (Figure 1) are difficult to assess. Our results suggest that the benefits (or costs) of marketing excess energy are related to the marginal generation costs of the utility's own plants, the operation and cost obligations of QF plants under contract to the utility, and the opportunities available in the unbundled generation market. Reductions in nongeneration costs, such as A&G costs (Figure 4), may have substantial effects on transition costs. The comparative importance of reducing specific nongeneration costs will depend on the cost structure of the utility in question. For our base-case utility, attaining benchmark performance in A&G costs reduces substantially its transition costs.

In general, we expect the absolute cost-reduction potential to be greater in A&G than in customer service (Figure 4) simply because industry-wide A&G costs are double customer-service costs. In addition, customer-service functions may become more important to utilities pursuing new or expanded market opportunities.

Strategies with medium effects change utility transition costs by 5% to 25%. Charging wheeling customers for ancillary services (Figure 3), reducing generation O&M costs (Figure 5), and discounting QF capacity payments to market prices (Figure 6) have medium effects on transition costs. Increasing

7/ As we compare individual strategies, we refer readers to the figure in the previous section containing the percentage effects for each strategy.

Table 2: Potential effects of different strategies on base-case utility transition costs[1]

Potential effect on utility transition costs	Strategy
Large (25% or greater)	• Rapidly open retail markets (+) • Delay retail wheeling (–) • Market excess energy (±) • Charge exit fees (–) • Reduce A&G costs (–) • Discount QF energy payments to market (–)
Medium (between 5% and 25%)	• Increase system load factors (±) • Accelerate depreciation of the generation plant (+) • Charge wheeling customers for ancillary services (–) • Reduce customer-service costs (–) • Reduce transmission O&M costs (–) • Reduce distribution O&M costs (–) • Reduce generation-plant O&M costs (–) • Discount QF capacity payments to market (–)
Modest (less than 5%)	• Accelerate depreciation of the generation plant and decelerate depreciation of the T&D plant (+) • Accelerate depreciation of regulatory assets (±) • Reduce public-policy-program costs (–)

1/ "+" indicates the strategy increases transition costs, "–" indicates the strategy decreases transition costs, "±" indicates the strategy may increase or decrease transition costs.

system load factors (Figure 1) may increase or decrease transition costs for utility shareholders, depending on the pricing structure used to recover fixed and variable costs and on whether on-peak sales are reduced or off-peak sales are increased. Accelerating depreciation of the generation plant (Figure 2) can have important effects on transition costs, depending on current depreciation expenses and the extent to which depreciation schedules are compressed. Some utilities can offset the increased costs of accelerated depreciation by decelerating the depreciation of other assets (Figure 2). Any transition costs remaining will be modest. Accelerated depreciation can also be applied to regulatory assets (Figure 2). Our results suggest that whether accelerating depreciation of these assets increases or reduces utility transition costs depends partly on when the change in depreciation begins.[8] If begun before retail wheeling starts, utility transition costs will decrease. If begun after wheeling starts, utility transition costs will probably increase. If the at-risk utility has substantial above-market generation costs or power-purchase contracts, the effects of regulatory asset depreciation will be modest.

Finally, reducing public-policy-program costs (Figure 4) has modest effects on transition costs for most utilities. The ultimate effect, of course, will be determined by the size of the initial programs and the extent of cuts; yet even a utility spending 5% or more of its annual revenues on these programs can hardly expect to achieve large reductions in transition costs.

Our analysis also suggests the need for more systematic assessments of specific strategies. Results from this study should be interpreted with some caution. The potential of specific cost-reduction options, for example, will depend on the cost structure of actual utilities. We recommend studies that assess strategies for utilities with cost structures that differ from the base-case utility examined here. For example, utilities with more expensive plants, with lower-cost or fewer QF contracts, or with nongeneration costs closer to industry averages may benefit from a somewhat different mix of strategies than the ones identified in

8/ This observation also holds for accelerated depreciation of generation assets. For example, the utility's transition costs will decrease if regulators permit a utility to recover the capital cost of its generation plants before retail wheeling begins.

this study. We have not determined whether the cost-performance benchmarks used in our study could be widely achieved. While utilities differ greatly in cost performance, we have not controlled for all the variables that could contribute to variations in costs, such as regional differences in wage rates. Nevertheless, the potential cost reductions are sufficiently large to warrant considerably closer examination in future studies.

Most of the strategies we examine require the cooperation of other parties, including regulators, to be implemented successfully. As a result, financial stakeholders must be engaged in negotiations that hold the promise of shared benefits. Only by rejecting "winner-take-all" strategies in favor of strategies that benefit multiple stakeholders will the transition-cost issue be expeditiously resolved.

Acknowledgements

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Appendix: Estimating Performance Benchmarks

We establish each benchmark using essentially the same process for each area of operations. Beginning with a database that contains all US electric utilities (RDI 1995), we select medium-to-large-sized investor-owned utilities that predominantly serve retail customers. From this subset of utilities, we then plot and examine the resulting frequency distribution for each cost variable. We estimate the mean, median, standard deviation, and range for each distribution and check carefully for outliers and other data problems. In most instances, we delete such observations from the relevant initial distribution, and subsequently replot the distribution and reestimate the descriptive statistics. For several of the cost variables, we also consider whether certain obvious utility characteristics are associated with the distributions. We look at the relationship between utility size and customer-service costs, for example, to determine whether economies of scale might be operating. Our intent here is to adjust for these effects when necessary. Only at this juncture do we estimate the approximate 90th percentile value for each cost distribution.

To illustrate, we apply the above process to the category of A&G costs. From the population of US electric utilities in 1994 (N = 3,206), we select utilities with summer peak demands greater than 499 MW (N = 200), with more than 100 retail customers (N = 148), and that are investor-owned (N = 115). We thus narrow our population of interest from the entire utility industry to this group of 115 firms. Figure A-1 presents a frequency distribution for A&G costs ($/customer) for these 115 firms and certain descriptive statistics. These utilities spend an average of $156/customer on A&G costs, but costs range widely—utilities spend as little as $64 and as much as $422/customer. Our inspection of the individual observations does not suggest any obvious outliers or data errors. In addition, we examine the correlation between A&G costs and utility sales (r = 0.14), number of residential customers (r = 0.05), number of total customers (r = 0.05), and customer mix (r = 0.00). None of these correlations suggest a significant association between A&G costs and the respective utility characteristics.[1] As a result, we find no reason to adjust the frequency distribution shown in Figure A-1.

Figure A-1 also presents the cumulative frequency distribution for A&G costs. The cumulative frequency distribution allows us to readily identify the approximate 90th percentile, which for this variable is about $96/customer. We apply the same process to customer-service costs, transmission O&M costs, and distribution O&M costs.

The procedure differs slightly for generation-plant O&M costs. Here we assume that cost-performance benchmarks can only be appropriately established by comparing plants of similar type and vintage. Thus, for each type of utility-owned plant in our base-case utility, we select plants from our national database with the same fuel type, combustion process, capacity, and vintage. We include O&M cost data from 1990 to 1994 to lessen the problem of an unusual year-specific O&M operation skewing the cost distribution. Thus, for the nuclear plant in our base case, we identify 48 comparable plants and use five years of O&M cost data for most of these plants. For the coal plant, we identify 36 comparable coal plants. From this point, we follow the same process used for the other cost variables to estimate the performance benchmark. The two natural-gas-fired plants in our base case have characteristics that provide a small comparison group (fewer than 30 observations). Instead of constructing plant O&M frequency distributions for these two plants, we estimate the average cost performance from 1990 to 1994 for the lowest-cost plant in the sample.

Table A-1 displays the base-case values and performance benchmarks for each of the cost

1/ The data did not allow the examination of all possible associations between utility costs and utility characteristics. For example, the relationship between T&D costs and the population or customer density of utility service areas was not examined

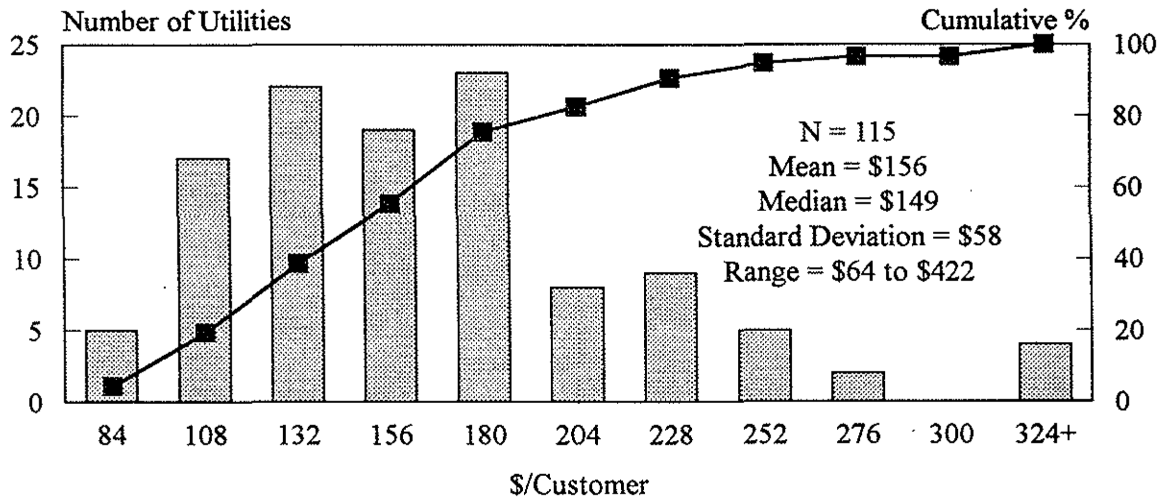

Figure A-1: Frequency and Cumulative Distributions for A&G Costs in 1995
Source: RDI, 1995

Table A-1: Performance benchmarks for utility cost variables (1994 $)

Cost Variable	Base-Case Value	Industry Average	Performance Benchmark
Administrative & general ($/customer)	231	156	96
Customer service ($/customer)	92	63	45
Transmission O&M ($/kW-year)	8	4	2
Distribution O&M ($/kW-year)	20	12	8
Generation Fixed O&M ($/kW-year)			
Nuclear	125	91	61
Coal	23	26	12
Natural Gas 1	13	21	8
Natural Gas 2	22	24	8
Oil	6	7	2
Hydro	4	12	3

variables we examined. In every instance, our cost assumptions for the base-case utility exceed the cost-performance benchmarks. The base-case utility's A&G, customer-service, transmission O&M, distribution O&M, and nuclear-plant O&M costs are also well above industry averages.