ASSESSING STRATEGIES TO ADDRESS TRANSITION COSTS IN A RESTRUCTURING ELECTRICITY INDUSTRY

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August 1996

Paper Prepared for Publication in the Proceedings of the 17th Annual North American Conference of the International Association for Energy Economics

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Assessing Strategies to Address Transition Costs in a Restructuring Electricity Industry[1]

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Restructuring the U.S. electricity industry has become the nation's central energy issue for the 1990s. Restructuring proposals at the federal and state levels 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 systematically assess strategies to address transition costs exposed by restructuring the electricity industry.

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. As the restructuring debate in the electricity industry enters its third year, 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, and 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 T&D network. The model includes a production-costing module, utility financial statements, and a rate-design module.

In assessing most strategies, we follow three steps.[2] First, we define a base-case utility, which is the reference point for our assessment. Second, we create 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. 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 results of the utility's operations for a calendar year. The income statement includes detail about revenues, expenses, and income. 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 expenses 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. Net income is the return to utility shareholders. 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 retail-wheeling scenario and the base case. The total transition costs are the sum of these annual differences, discounted to present value dollars.

$$Net\ Income_t = Revenues_t - Expenses_t$$

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

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. In practice, determining 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. 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.

The Base-Case Utility

The base-case utility is developed from a substantial amount of actual utility data from 1993 and 1994. We select a utility that faces potentially substantial transition costs arising from each of three 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 (Resource Data International 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.

As of 1995, the base-case utility is investor-owned with a rate base of $7.3 billion, common equity of $3.2 billion, and revenues of $4.6 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 (about 2800 MW) have "must-run" provisions; that is, the utility must purchase power from these facilities when they are available. The combined capacity and energy payments for these must-run 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. We characterize the unbundled generation market using four price blocks. 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 residential rates (12.4 vs 8.4¢/kWh), commercial/industrial rates (9.9 vs 6.1¢/kWh), and total production costs (5.7 vs 4.5¢/kWh) are substantially higher than national averages for electric utilities (Energy Information Administration 1995). Most importantly for potential transition costs, the utility's average 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 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 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 assumptions about the timing and pace of

retailing are developed exogenously and then incorporated in ORFIN. We hold these wheeling percentages constant so that these same fractions of new customers (60% commercial and industrial, 40% residential) entering the utility's former service area become wheeling customers. As noted earlier, we also assume that retail rates are the same in the base case and the retail-wheeling case. As a result, the revenue losses from retail wheeling are borne by utility shareholders.

Under the retail-wheeling scenario, utility 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 before declining gradually to $510 million by 2005 (in nominal terms). The total transition costs are $2449 million under the retail-wheeling scenario [1996–2005, net present value (NPV)], which represents 77% of the utility's equity as of 1995.

Transition-Cost Strategies Assessed

We review filings at federal and state proceedings, published literature, industry press, and consultant reports to compile a list of available strategies. We group the many individual strategies into six major categories:

- ▸ Market actions affect the market structure for electricity or rely on market mechanisms.
- ▸ Depreciation options modify the depreciation of utility assets.
- ▸ Rate-making actions change the rates utilities charge for electricity service.
- ▸ Utility cost reductions offset transition costs or lower electricity prices.
- ▸ Tax measures increase taxes or use tax reductions or deductions.
- ▸ Other options include a handful of strategies not falling in the first five categories.

In this paper, we assess strategies from the first four categories (Table 1). 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.

ASSESSMENT RESULTS

Market Actions

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-

Table 1. Effects of Specific Strategies on Utility Transition Costs

Specific Strategies (Reference Value)	New Value	Transition Costs (millions $)	Δ fr RW Scenario (millions $)[a]	Δ fr RW Scenario (%)
Market actions				
Delay wheeling (begin 1996; max 2000)	begin 1998; max 2005	1661	-788	-32.2
Reduce retail demand (3742 MW)[b]	3564 MW	2657	208	8.5
Increase retail sales (21455 GWh)[b]	22525 GWh	2284	-165	-6.7
No excess sales (29171 GWh)[b]	7666 GWh	2338	-111	-4.5
No excess sales [w/QF purchases, (29171 GWh)][b]	14155 GWh	3111	662	27.0
Depreciation options				
Accelerate nuclear plant (30 yrs)	12 yrs	2568	119	4.9
Accelerate nuclear plant (30 yrs); decelerate T&D plant (50 yrs)	12 yrs; 75 yrs	2498	49	2.0
Accelerate regulatory asset (12 yrs)	3 yrs	2411	-38	-1.6
Rate-making actions				
Sell ancillary services ($0)	$20/kW-yr	2209	-240	-9.8
Exit fees [constant costs, ($0)]	see Table 2	-1138	-3587	-146.5
Exit fees [changing costs, ($0)]	see Table 2	86	-2363	-96.5
Utility cost reductions				
Customer service ($92/customer)	$45/customer	2068	-381	-15.6
Administrative & general ($323/customer)	$154/customer	1400	-1049	-42.8
Transmission O&M ($8/kW-yr)	$2/kW-yr	2255	-194	-7.9
Distribution O&M ($20/kW-yr)	$8/kW-yr	2203	-246	-10.0
Public-policy programs ($30 million/yr)	$7 million/yr	2426	-23	-1.0
Nuclear & Coal Generation O&M ($69/kW-yr)	$34/kW-yr	1982	-467	-19.1
QF capacity at market ($77/kW-yr)	$40/kW-yr	2039	-410	-16.7
QF energy at market (6¢/kWh)	2.5¢/kWh	-32	-2481	-101.3

[a]Transition costs for the base-case utility under the retail wheeling scenario are $2449 million.
[b]Reference and new values differ for each year in the forecast. Reported values are for the year 2000.

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, once wheeling begins, the utility has more time to depreciate sunk costs.

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 effectively manage loads 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. The alternative strategy, increasing off-peak sales, increases utility expenses, but the resulting revenue increase exceeds the costs. 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 $2449 million from the retail-wheeling scenario already reflect any benefits and costs derived from increased unbundled generation sales. To estimate these effects, therefore, we set 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 the lost retail sales to unbundled generation sales. The result is a 4% reduction ($110 million) in utility transition costs. This counterintuitive result is explained by examining the change in unbundled generation-sales revenue and in production costs between the initial and revised retail-wheeling scenarios. In the revised retail-wheeling scenario, the utility experiences a decline in generation-sales revenue consistent with its lower generation sales. But over the ten-year analysis period, the decrease in production costs (fuel and variable O&M) from its own plants and from its most expensive long-term contracts more than offsets the revenue loss. ORFIN responds to the lower level of generation sales by reducing generation from utility-owned plants as well as by reducing purchases from the must-run QF contracts; this latter effect is particularly important. If the utility is able to reduce purchases from these must-run contracts, whose costs exceed 7¢/kWh, the production-cost savings are substantial. When do lower expenses more than offset lower revenues? For our base-case utility, only when the retail-wheeling levels become substantial.

We examine a second case where all the utility resources except the QF must-run 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-run 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

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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.

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 $50 million (i.e., transition costs decrease about 3 percentage points or $70 million relative to the accelerated depreciation strategy).

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. 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. Based on work at ORNL to assess ancillary service costs at 12 U.S. 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 establishes for certain departing wholesale customers (FERC 1996). Exit fees could also be applied to departing retail customers. As a first step, we estimate a one-time exit fee for the two customer classes in the base-case utility. Of course, an exit fee can also be structured as a stream of payments, presumably with carrying charges, but for simplicity we assume customers pay an exit 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:

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

$$\times\ average\ electricity\ use_{r,\ 1994}$$

The exit fee for year c and customer class r 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 (e.g., 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 this difference 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 2 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

Table 2. One-Time Exit Fees for Successive Cohorts of Departing Customers (1994 $)

	1996	1997	1998	1999	2000
Residential customers					
Constant generation costs		2331	2171	2017	1872
Changing generation costs		1500	1400	1303	1209
Commercial & industrial customers					
Constant generation costs	53,059	49,393	45,898		
Changing generation costs	34,046	31,780	29,598		

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 %, which *eliminates the utility's transition costs and results in a gain of $1140 million in net income from 1996 to* 2005. The lower exit fees eliminate 96% of the utility's transition costs ($2360 million). 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 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 nongeneration 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. The transition-cost-recovery process itself could also provide utilities an incentive to reduce costs if a meaningful portion of these reductions are used to offset transition costs.

Table 1 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 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 Table 1. 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 these budget cuts are accompanied by reductions in services or benefits. As a result, we redefine the base-case utility to reflect the 75% program reductions 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 the utility's 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.

Table 1 presents results of the utility's achieving performance benchmarks for generation-plant O&M. 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 and the results are omitted from Table 1.

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 2,750 MW of "must-run" QF contracts. The utility's energy payments to the must-run QFs are about $1 billion/year, with the balance being capacity payments.

We examine two strategies to reduce the utility's power-purchase costs. 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-run 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 et al. 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 maintains the must-run contract provisions but discounts the energy payments to the average market price of 2.5¢/kWh. The utility's unbundled generation sales return to the level projected in the retail-wheeling scenario as do revenues from these sales, but power-purchase contract costs decrease substantially. As a result, total power-purchase costs decline dramatically, and the utility's transition costs are eliminated.

From the above analysis, we see that the strategy that discounts energy payments to market prices produces 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

Strategies with potentially large effects change transition costs to utility shareholders by 25% or more. For at-risk utilities, delaying retail wheeling, charging exit fees to departing customers, and discounting energy payments to QFs to market prices are all likely to result in large reductions in utility transition costs. Rapidly opening retail markets 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 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 administrative and general costs, 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.

Strategies with medium effects change utility transition costs by 5% to 25%. Charging wheeling customers for ancillary services and discounting QF capacity payments to market prices have medium effects on transition costs. Accelerating depreciation of the generation plant can have quite large 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. Any transition costs remaining will be modest. Accelerated depreciation can also be applied to regulatory assets.

Finally, reducing public-policy-program costs 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 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.

ENDNOTES

1.   This work was sponsored by the Coal and Electric Analysis Branch, Energy Information Administration. Our views do not necessarily reflect those of the Energy Information Administration.

2. Details on the assessment framework, modeling approach, key assumptions, and results are contained in Baxter, L., Hadley, S., and Hirst, E. (1996). *Strategies to Address Transition Costs in the Electricity Industry*. ORNL/CON-431, Oak Ridge National Laboratory. Copies of the report can be obtained by writing L. Baxter at Oak Ridge National Laboratory, P.O. Box 2008, Oak Ridge, TN 37831-6205.

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