What's 'Sunk' Ain't Stranded

Questioning front-end assumptions in computing stranded investment.

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IN THE DECEMBER ISSUE OF PUBLIC UTILITIES FORTNIGHTLY, author Eric Hirst presented a theoretical framework for analyzing the effects of future market prices on stranded-cost recovery.[1] His approach addresses the uncertainty of "a priori estimates of stranded costs." He urges regulators to take a "going forward" approach. First examine how competitors behave. Then make sure that utilities operate their assets just as efficiently before locking in any estimates of stranded costs.

The Hirst framework, however, also contains one potentially fatal flaw – it assumes that positive stranded costs actually exist. This isn't so different from the recent decision by the Michigan Public Service Commission to declare stranded all of Detroit Edison's investment related to the Fermi 2 nuclear plant.[2] That decision left consumers and company alike with no option except to argue about when and how Detroit Edison would recover its so-called "stranded costs."[3]

Instead, we offer a different view. What if some so-called "sunk" costs are not so sunk? What if depreciation, usually thought of as an unavoidable fixed cost, is actually avoidable? We suggest that both in past and potentially on a going-forward basis, utilities have recorded excessive depreciation allowances. In short, we contend that Mr. Hirst's approach would build these excessive allowances into the resulting stranded-cost estimation. Regulators need to "get it right" before ever considering stranded costs. Our strategy for improving stranded cost estimation and mitigation considers the following points:

- **FOSSIL DEPRECIATION TOO HIGH.** This over-depreciation helps explain a portion of the high markups beyond book value paid for older power plants at auctions throughout the country. That excess is money from the pockets of current ratepayers. Utilities should not be allowed to keep it or to use it to benefit shareholders through stock repurchases or debt reduction.
- **DISMANTLEMENT UNLIKELY.** It's improbable that fossil fuel plants ever will be fully dismantled. Units or parts of units are retired, but few whole plants have been retired-—especially large plants. There is a far greater chance of the plant being replaced piecemeal, repowered or sold at a profit than there is of the plant being fully dismantled. In any case, utilities aren't obligated to pay dismantled costs after deregulation.
- **TAKE A "LOOKING BACKWARD" APPROACH.** Adjust the depreciation reserve before (or while) determining stranded costs to promote "intergenerational equity" in rates. Regulators should decide on the appropriateness of competitive markets only after repaying ratepayers for excessive collections and after ratepayers have received the rate cuts they deserve. Current ratepayers should not pay excessively so that future ratepayers (especially large ones) can save money.
- **EMULATE COMPETITION.** Adjusting depreciation rate to reflect competitive behavior, such as expensing removal costs as they occur and using realistic service lives for plants, can reduce the price at which a plant or portfolio can compete in the future without incurring stranded costs. Reducing or eliminating a guaranteed return on equity in addition to the return of capital can reduce break-even market prices even further.

Over-Recovery: A Negative Stranded Cost

Our analysis of Hirst's method provides many points of agreement. We agree with the concepts that utilities should be responsible for "going forward' operating costs. Most savvy investor-owned utilities have made strides in reducing operating costs in the face of impending deregulation. They should be able to operate at the same cost as independent power producers.

We also agree that stranded cost should be limited to costs that can't be avoided. We disagree, however, with Hirst's definition of unavoidable costs:

> "depreciation, property and income taxes, interest payments and return equity."

This includes all capital costs. Hirst's method makes the ratepayer responsible for all of them at current levels, even after deregulation. Even if one accepts the questionable inclusion of return on equity (the regulatory compact requires only a return of capital) and income taxes (a plant returning less than its costs would have no income tax) as unavoidable costs, it is impossible to accept depreciation expense resulting from the application of current depreciation rates as fixed, immutable and unavoidable costs.

This is not a small problem. The table, Regional Weighted Averages of "Unavoidable" Fixed Costs, shows the composite regional and national proportions of capital costs ("unavoidable"), related to generation represented by current depreciation rates (36.1%). It also provides us inputs with which to analyze the model presented by Hirst.

The problem in using that model for stranded-cost recovery is that the depreciation expense resulting from the application of current rates often serve to "hide"over-recovery of capital, both under regulation and "going forward". Such over-recovery is the reverse of stranded costs—a negative cost that represents capital funds advanced to the utility by ratepayers.

The Reasons Behind Over-Depreciation

Our studies indicate that this condition is pervasive—the result of depreciation rates that have been far too high for too many years.

Why is that the case? There are three reasons:

INTENTIONAL DEPRECIATION INCREASES. Depreciation is non-cash expense, so high depreciation charges don't increase the utility's cash outlay. To the contrary, under cost-based regulation, increasing depreciation increases cash flow. It is particularly useful to mask over-earnings when costs are declining. By increasing depreciation expense, the utility can avoid triggering an expensive rate case, which would probably result in lower, near -term service rates.

However, in the normal course of regulation, higher depreciation rates ultimately reduce the rate base, which eventually should lead to long-term rate reductions. Provided the rate reductions aren't delayed too long or the excess earnings situation is short-lived, the cost to ratepayers is small. With deregulation, however, the intergenerational inequity, manifested in the accumulated depreciation reserve excess, becomes permanent. Tomorrow's ratepayers will never be repaid for a rate decrease foregone today.

Regional Weighted Averages of "Unavoidable" Fixed Costs (in cents/kWh)							
NERC Region	**Depreciation**	**Property Taxes**	**Income Taxes**	**Interest**	**ROE**	**Total**	**Depreciation**
ECAR	0.59	0.25	0.18	0.24	0.28	1.54	38.3%
ERCOT	0.53	0.35	0.20	0.39	0.47	1.94	27.3%
FRCC	0.71	0.31	0.15	0.14	0.27	1.58	44.9%
MAAC	0.83	0.45	0.19	0.34	0.41	2.22	37.4%
MAIN	0.64	0.42	0.17	0.32	0.35	1.90	33.7%
MAPP	0.49	0.22	0.14	0.18	0.28	1.31	37.4%
NEPOOL	1.01	0.46	0.18	0.58	0.58	2.81	35.9%
NYPP	.085	1.06	0.21	0.50	0.56	3.18	26.7%
SERC	0.47	0.19	0.24	0.21	0.36	1.47	32.0%
SPP	0.43	0.17	0.19	0.27	0.30	1.36	31.6%
WSCC	1.09	0.16	0.16	0.27	0.32	2.00	54.5%
Average	**0.70**	**0.37**	**0.18**	**0.31**	**0.38**	**1.94**	**36.1%**
Source:"1997 Electricity Price and Production Cost Report," Donaldson, Lufkin & Jenerrette, Oct. 1998, pp. 36-47.							

"UNINTENTIONAL" DEPRECIATION INCREASES". The estimated lifetimes during which the investment in most power plants is depreciated are based upon unsupportable concepts and engineering estimates. Life extension programs (or "plant optimization programs") implemented during the past 20 years have extended plant service lives well beyond the finite and typical depreciation lifespans of 30 to 40 years.

Studies on the impacts of life extension programs in the 1980s by Edison Electric Institute, the Electric Power Research Institute and the U.S Department of Energy recognized that plans were being used longer (see "Extended Lifetimes for Coal-fired Power Plants: Effect Upon Air Quality," James DeMocker, Judith Greenwald and Paul Schwengels, Public Utilities Fortnightly, March 20, 1986, pp. 30-37). A followup study performed for the California Energy Commission showed that of 172 plants considered for life extensions, repowering or retirement, only 14, or 8.14 percent, actually were retired (see "Acid Rain Impacts on Utility Plans for Plant Life Extension," Jill S. Baylor, Public Utilities Fortnightly, March 1, 1990, pp. 22-28).

Our firm has completed a study using actuarial methods that confirms these trends have continued. When adjusted for the interim retirement experience, the average service life (not lifespan) of assets in steam power plants is generally 45 to 55 years. The average service life for assets in hydro facilities is much longer.4 The use of 30-to-40 year lifespans, rather than the more realistic 45-to-55-year average service lives of equipment, has led to unintentional increases in depreciation rates. This effect would be reflected in the stranded-cost recovery method proposed by Hirst.

INFLATED DISMANTLEMENT COSTS. Additional excessive depreciation comes from the exaggerated view many utilities take of exposure to the cost of dismantling non-nuclear power plants. The utilities assume that they will be obliged to dismantle each plant to "greenfield" status—its original condition—when the present generating units retire.

Estimates of $30 to $100 per kilowatt in current dollars are commonly incorporated into depreciation rates.5 These dismantlement costs are added to the capital to be recovered through depreciation. They're charged as a cost of service to current ratepayers. When utilities file cash flow estimates of stranded costs, these amounts are further inflated to future dollars and added to their calculations (the big number at the end of the artificially shortened life of the plant).

The reality is that most fossil plants won't be dismantled when the present generating units are retired and few, if any, hydro plants will be dismantled at the end of their license period.6 Typically a steam plant containing retired units have units continues on, either with new or repowered steam units or as the site for peaking turbines.

There have been 67 large (over 50 megawatts) steam units retired during the past decade. Very few have been dismantled. None has involved costs remotely approaching those incorporated into depreciation rates by some utilities.

These exaggerated dismantlement cost allowances inflate depreciation rates and contribute heavily to the excess reserve embedded in most utilities' plant accounts. Once again, under regulation, the effect is to lower the rate base, which eventually leads to rate decreases. However, under deregulation in the Hirst model, there usually is no obligation for the stockholders to use dismantlement money for the purpose it was collected. In competitive market, the past excessive collections from ratepayers become shareholder income.7

Get It Right, Then "Go Forward"

The above reasons show why it is critical for regulators to review past depreciation rates, practices and reserves before deciding if any utility should receive stranded cost recovery. Imagine that the above difference in depreciation rates has gone on for years. The excess depreciation grows and grows. Finally, only recent capital additions remain to be depreciated. Yet the plant still runs fine. The capital cost to build a new plant far exceeds the impacts of negative heat rate or operating and maintenance expense comparisons with newer plants capable of serving the same customers. Is it any surprise that such a plant would sell for two to four times its underlying book value?

In practice, we've found reserve excesses containing hundreds of millions of dollars for portfolios of non-nuclear generation assets. This excess is "real" money that has been overpaid by current ratepayers in the name of intergenerational equity. It should be paid back to current ratepayers before allowing utilities or future ratepayers to enjoy deregulation.

Intergenerational equity requires repayment even if it produces higher book values that would give the appearance of greater stranded costs (or smaller negative stranded costs). If the plants have been sold at market prices incorporating those excess collections, then that part of the profits should automatically revert back to ratepayers. Ideally this point should be determined before beginning stranded-cost deliberations.

Adjusting the future depreciation rates to reflect competitive conditions also affects stranded costs. Using the "going forward" model proposed by Hirst, we've presented the results of that model8 superimposed with a curve representing the allowable stranded costs for the same hypothetical plant (see figure, Allowable Stranded Costs), with depreciation rate adjusted for realistic service lives and net salvage values.

The model incorporates "avoidable" fixed costs of operation and maintenance expenses, administrative and general expenses and capital additions of $16/kW. Certain capacity factor and market price/revenue relationships also are assumed in the Hirst curve and have been repeated in our curves. We have adjusted only costs referred to as "unavoidable" fixed costs, which we feel are very avoidable indeed.

The first of those "constants" we adjusted is depreciation. In our experience, changing life spans and net salvage to reflect recent trends and experiences could substantially reduce current depreciation rates. A 35 percent reduction of rates reduces the allowable stranded costs by about 12.6 percent ($2.25/kW). It also reduces the price at which the plant or generation portfolio can operate without incurring stranded costs, from 2.67 cents to 2.62 cents (1.5 percent). This excessive depreciation would otherwise be collected through a competitive transition charge, or CTC regardless of electricity's market price. In the case of a negative CTC, it would reduce the amount paid back to ratepayers. The over-collections become very large relative to the total stranded costs as the stranded cost (positive or negative) approaches zero.

Suppose regulators also decided to take issue with the inclusion of guaranteed return on equity with stranded costs in addition to a return of capital. Reducing or eliminating that return could be a valid course of action. In an environment of declining costs and interest rates, the return on equity, or ROE, undoubtedly would be reduced in the future anyway.[9]

Many companies have not had their allowable returns adjusted in years. Once arrangements have been made to return capital through a CTC or some other method, the investment becomes safer. It should require a lower return. And in a competitive environment, the company can always sell its plants if it wants to make a greater return on a riskier investment or limit itself to regulated business. The elimination of ROE (19.6 percent $3.92/kW) and expected income taxes on ROE (9.3 percent or $1.86/kW) using amounts shown in the table would further reduce the maximum allowable stranded costs in this model to $11.70/kW (41.5 percent reduction). The market price at which the plant can operate and still obtain a return of capital, as well as interest and property taxes (and other non-income taxes) has now been reduced to $2.52 cents/kW—a reduction of 5.62 percent (as shown in the allowable costs figures).

Our purpose isn't to disparage Mr. Hirst's article. We want to stress the importance of "balancing the books" before "going forward' into deregulation. We have seen too many cases where regulators start with the assumption that there actually are stranded costs. Then they search for "going forward" economic models to explain how the utility will go about recovering those stranded costs.

In most cases, there are no positive stranded costs related to non-nuclear generation. It is far more important to give ratepayers the rate cuts that they should have gotten years ago first—not as a payment for accepting deregulation. If regulators and legislators then feel that competition will lower costs and rates even further, deregulation is a good path to follow.

1) Hirst, Eric, ‘Stranded Costs: What to Allow, What Not." Public Utilities Fortnightly, December 1998, p. 70.

2) MPSC Case No. U-11290, June 5, 1997, Opinion and Order, p. 7.

3) Testimony of Michael J. Majoros, Jr. and others, MPSC Case No. U-11926, Sept. 15, 1998.

4) "National Study: U.S. Generating Unit Retirement Age," Snavely King Majoros O'Connor & Lee, Inc., 1998.

5) The rates for dismantlement are further exaggerated by the common practice of dividing the net salvage (salvage revenue minus decommissioning cost) in current dollars by the remaining investment dollars in dollars denominated at the time the plant was built to arrive at a "net salvage rate."

6) To date, the Federal Energy Regulatory Commission has refused to renew an incumbent utility's hydro operating license only one time, in the recent denial for environmental reasons of the license for Edwards Dam on the Kennebec River, Maine. In that case, the state and environmental groups took responsibility for dismantlement.

7) Note that decommissioning (net salvage) costs for most nuclear plants are kept in separate accounts. The average service life, likewise, is determined by its operating license. Barring a successful application for license extension or excessive accelerated depreciation allowed in the past, there still is a possibility of stranded costs with nuclear generating assets (nuclear plants aren't currently being sold at multiples of book value either).

8) We generated an estimated curve of "allowable" stranded costs from the stranded cost per kilowatt numbers presented in the text of the Hirst article. For some inexplicable reason, the numbers in Hirst's text did not exactly match the curve presented in the article.

9) Hyman, L., "America's Utilities: Past, Present and Future, "Public Utilities Report, 1994, pp. 189-191.