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Estimating Potential Stranded Commitments for U.S. Investor-Owned Electric Utilities

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ESTIMATING POTENTIAL STRANDED COMMITMENTS FOR U.S. INVESTOR-OWNED ELECTRIC UTILITIES

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SUMMARY

New technologies, low natural gas prices, and federal and state utility regulations are restructuring the electricity industry. Yesterday's vertically integrated utility with a retail monopoly franchise may be a very different organization in a few years. Conferences, regulatory-commission hearings, and other industry fora are dominated by debates over the extent and form of utility deintegration, wholesale competition, and retail wheeling.

A key obstacle to restructuring the electricity industry is stranded commitments. Past investments, power-purchase contracts, and public-policy-driven programs that made sense in an era of cost-of-service regulation may not be cost-effective in a competitive power market. Regulators, utilities, and other parties face tough decisions concerning the mitigation and allocation of these stranded commitments.

We developed and applied a simple method to calculate the amount of stranded commitments facing U.S. investor-owned electric utilities. The results obtained with this method depend strongly on a few key assumptions: (1) the fraction of utility sales that is at risk with respect to competition, (2) the market price of electric generation, and (3) the number of years during which the utility would lose money because of differences between its embedded cost of production and the market price.

We calculated stranded commitments assuming that only industrial customers could "leave" the local utility's system or that all retail customers would have such options. We assumed that the appropriate market price was the capital costs plus operating costs of a combined-cycle combustion turbine or a price between that of the combined-cycle unit and short-run operating cost based on the region's capacity margin. We tested the sensitivity of results to two other assumed prices: the regional average industrial price or the short-run operating cost of existing generation. We assumed that these losses would occur for five, ten, or fifteen years. We used the nine North American Electric Reliability Council regions to define the boundaries for the regional power markets.

Estimates of stranded commitment can vary widely depending on the assumptions used. We believe that such losses could range from less than 40% to more than 50% of utility equity (Table S-1). The lower number might obtain if only industrial customers can leave the system and if the market price of electricity is a function of capacity margins in the region and ranges between the combined-cycle cost and the short-term operating cost. The higher value might occur if all retail customers have choices and the market price is that of a combined-cycle unit. In both

cases, losses are concentrated in a few states, including California, New York, Ohio, and Pennsylvania. Utilities in Kentucky, Missouri, Montana, Virginia, and Washington, on the other hand, face little threat of stranded commitments.

Table S-1. Potential stranded commitment in billions of 1992 dollars (and as percent of equity) as a function of portion of load at risk and market price of generation

	Market price[a]			
Portion of load at risk	Industrial average	Combined-cycle turbine	Capacity adjusted	Short-run marginal cost
Industrial only	15 (8%)	34 (19%)	69 (38%)	83 (45%)
All retail	39 (21%)	99 (54%)	210 (115%)	256 (140%)

[a]The assumed market prices decline from left to right.

At any market price, the loss to utility shareholders is 2.5 to 3 times as great when all retail loads are at risk than when only industrial loads are at risk. Raising the assumed market price of electricity by 1¢/kWh decreases the equity loss by 25 percentage points for all retail customers and by 10 percentage points for the industrial class only. Lowering the market price by 1¢/kWh increases the equity loss by 33 and 14 percentage points, respectively. For the all-retail case, the change in stranded commitments is about $60 billion for every 1.0¢/kWh change in the market price of electricity.

If these earnings losses occur unchanged for only five years (rather than the ten years assumed above), the equity loss would be cut by 40% . On the other hand, if the revenue losses were to occur for 15 years, then the equity loss would increase by almost 30%.

The range of results presented here illustrates the importance of the assumptions used to estimate the amounts of stranded commitments that individual utilities might face. Regulatory commissions need to examine closely the underlying assumptions, as well as the data and analytical tools, used to develop these estimates in deciding how to mitigate and allocate these costs.

LIST OF ACRONYMS

CCCT	Combined-cycle combustion turbine
ECAR	East Central Area Reliability Coordination Agreement
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
IOU	Investor-owned utility
MAIN	Mid-American Interpool Network
MAAC	Mid-Atlantic Area Council
MAPP	Mid-Continent Area Power Pool
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NPV	Net present value
SC	Stranded commitments
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
WSCC	Western Systems Coordinating Council

INTRODUCTION

Technology advances, low natural gas prices, and legislative initiatives are changing the electricity industry. Because of the 1978 Public Utility Regulatory Policies Act, electric utilities are no longer the sole providers of generation capacity in the United States. The Energy Policy Act of 1992 mandates open and nondiscriminatory access to the transmission system for all suppliers. Many customers (especially the large industrials) want the freedom to choose their electricity provider over this open transmission system. As a result, future industry restructuring could lead to widespread competition among suppliers to meet customer demands.

With widespread competition, a utility will use its own generation mix to compete for market share with other suppliers. If the utility's rates exceed market-clearing prices for electricity, then the utility has a strong incentive to reduce its rates to maintain market share. These price reductions, however, will reduce the utility's revenues and earnings. If the revenue from the sale of its output is now less than its total (capital and operating) cost of production, then some commitments the utility made in the past are now uneconomical.

These two forces, the loss of revenues needed to cover costs and the existence of uneconomical commitments, explain why utilities are concerned that their existing commitments may become "stranded," that is, commitments that no one explicitly pays for.

The policy relevance of these uneconomical commitments is that utilities made them during an era of prudence review and public regulation. Regulators considering industry restructuring must squarely address how to deal with commitments that now appear to be uneconomical but that the industry made with the regulators' approval and with the expectation that the long-standing regulatory compact (which includes the utility's obligation to serve all customers in return for a retail monopoly franchise) would continue. By proposing to alter the regulatory compact by changing the industry structure, regulators raise serious policy questions about uneconomical utility commitments. If the commitments were deemed prudent under the traditional regulatory compact, who bears the burden of paying for the undepreciated balance of these commitments in the restructured industry? How large is this stranded-commitment burden? How should this amount be determined? To what extent can it be reduced?

Stranded commitments (SC) can include four classes of costs (Niagara Mohawk Power Corp. 1994):

- Stranded assets, primarily in expensive power plants and excess capacity

- Stranded liabilities, primarily in power-purchase contracts (including those with qualifying facilities) and deferred income taxes

- Regulatory assets (whose value is based on regulatory decisions rather than on market forces), including deferred expenses and costs for demand-side management programs that regulators allow utilities to place on their balance sheets

- Stranded public-policy programs, including tax collection, environmental compliance beyond that required by law, demand-side management programs paid for by all customers, special programs for low-income customers, and support for energy research and development.

A full treatment of SC would consider (1) alternative ways to calculate SC; (2) estimates of the amount of SC for each utility; (3) methods to mitigate (reduce) these amounts; and (4) allocation of the remaining SC among utility shareholders, different classes of customers, and governments (i.e., taxpayers in general). This report, the first output from a larger Oak Ridge National Laboratory project on stranded commitments, deals only with the first two issues. See Hogan (1994) and Steinmeier and Stuntz (1994) for initial discussions of the latter two issues.

Chapter 2 illustrates the wide range in estimates of SC that exist today and explains the various factors that account for this large range. Chapter 3 discusses alternative ways to calculate SC, and Chapter 4 presents our approach to these computations. Chapter 5 presents our results, and Chapter 6 identifies the key assumptions that underlie our analysis. Chapter 7 offers initial conclusions concerning methods to calculate SC and the resultant amounts. The Appendix contains several tables that provide additional details on the assumptions and results presented here.

PRIOR ESTIMATES OF STRANDED COMMITMENTS

Estimates of SC vary widely. Niagara Mohawk (1994) estimates these costs "as high as 150 to 200 billion dollars, compared to a total shareholder equity of 180 billion dollars." Perl (1994) states that "if rates charged for generation were to fall to marginal cost (with no change in transmission or distribution charges) the market value of utility capital would fall by more than $500 billion. Since the market value of utility stock is about $250 billion, this provides a pretty good picture of disaster. Even if only industrial rates were driven to marginal cost, the value of utility capital would fall by $160 billion ... ." At the other end of the spectrum, Hobart (1994) estimates these potential losses at $10 to $20 billion. Unfortunately, some of these estimates were not supported by data and analysis in the publication cited, which makes it difficult to examine and assess the assumptions used to develop these numbers.

The high estimates cited above may be based on notions of *gross* SC, which would include only the noneconomical assets, contracts, and so on. Estimates of *net* SC would reflect the difference between uneconomical and economical assets, where economical assets are those whose market value is higher than book value.

To illustrate the difference between net and gross SC, consider a utility that operates a nuclear plant. The plant's operating cost of 1.2¢/kWh makes it very competitive on the spot market, but its high capital cost of 5¢/kWh makes it uneconomical relative to a new combined-cycle combustion turbine (CCCT). The difference between the utility's 6.2¢/kWh cost to own and operate its nuclear plant and the roughly 3.8¢/kWh cost to own and operate a CCCT could be considered stranded. However, the same utility surely owns some power plants (as well as other assets) that are largely depreciated (e.g., a 30-year-old coal plant). Although these assets may be nearing the ends of their economic lives, their operating lives might be quite long.* This old coal plant, with an operating cost of 1.5¢/kWh and a capital cost of 1.7¢/kWh, is very competitive with the combined-cycle unit. Indeed, this coal plant could yield "freed" commitments in a competitive market of 0.6¢/kWh. The point to remember is that a complete assessment of this utility's competitive position should include both the high-cost assets and the low-cost assets.

Feiler (1994) examined the potential liabilities associated with power-purchase contracts. His analysis, based on more than 7300 transactions, "suggests that the potential stranded liability

*Consider a power plant with a 40-year book life and a 20-year tax life. The plant's annual capital cost (depreciation, taxes, interest payments, and shareholder return) in year 20 is less than half of that in year 1. By the 30th year, the annual cost is only 30% of that in year 1.

from above-market, power-purchase contracts for electric utilities is over $15 billion annually." Important as this estimate may be, it provides only a partial picture of a utility's vulnerability to increased competition. One must also look at contracts with below-market prices, power plants whose capital and operating costs are below market prices, and so on to gain a complete picture of the utility's situation.

These disparate estimates of SC also reflect very different assumptions. Our analysis, discussed below, suggests that a few assumptions are crucial in determining the magnitude of the SC estimated. These key assumptions concern the fraction of a utility's customers that can exercise choices in selecting alternative power suppliers; the market price of electricity; and the dynamics of a transition from today's vertically integrated, regulated, retail-monopoly-franchise system to some future, more competitive structure. Not surprisingly, these three factors are interdependent. More customers will likely be eligible for choices the longer the transition period considered. The market price of power will likely be directly related to the number of potential customers for competitive electricity. With few buyers (e.g., if only a few large industrial customers are able to leave the local utility system), market prices for those customers may be quite low for several years. On the other hand, if all customers are able to obtain electricity supplies from a competitive marketplace, prices are likely to be much higher (Fig. 1). As Hempling, Rose, and Burns (1994) note:

> As a technical matter, estimating [stranded commitments] requires estimating future market prices. No one knows what future market prices will be, for several reasons. The most prominent reason is that no one knows the future industry's structure, because it is being debated now. ... There also is a dynamic nature to the problem. Markets evolve in complex and unpredictable ways. Even if one estimated the future marginal costs of some industry players, one could not estimate how competitors including utilities will respond. Moreover, the playing field will depend on the cumulative effect of numerous government decisions about wholesale competition, retail competition, mergers, future rate design, municipalization, and externalities in prices, to name only a few factors.

Finally, some of the estimates cited above may have ignored the effects of federal and state income taxes. Any losses experienced by utility stockholders are automatically shared with taxpayers. If the average income tax rate is 35%, then utility shareholders pay for only 65% of the SC.

To illustrate the effects of income taxes, consider the situation shown in Table 1. The utility sells 23,552 GWh in a particular year at a price of 7.21¢/kWh (the utility's price of 7.00¢/kWh plus a 3% sales tax). As shown in the second column, the utility's net income in this case is $187.4 million. If, because of competitive forces, the utility cuts its price by 10% (to 6.30¢/kWh plus the 3% sales tax), its revenue is cut by the same 10%, $170 million. However, this $170 million revenue reduction is partially offset by a sales-tax reduction of $5 million plus an income-tax reduction of $59 million. The income-tax reduction is a function of the utility's 36% income-tax rate, and the sales-tax reduction is a function of its 3% sales-tax rate. Thus, the shareholder loss is 64% (100% - 36%) of the net revenue loss to the utility {$105/[$170 * (100 - 3%)]}.

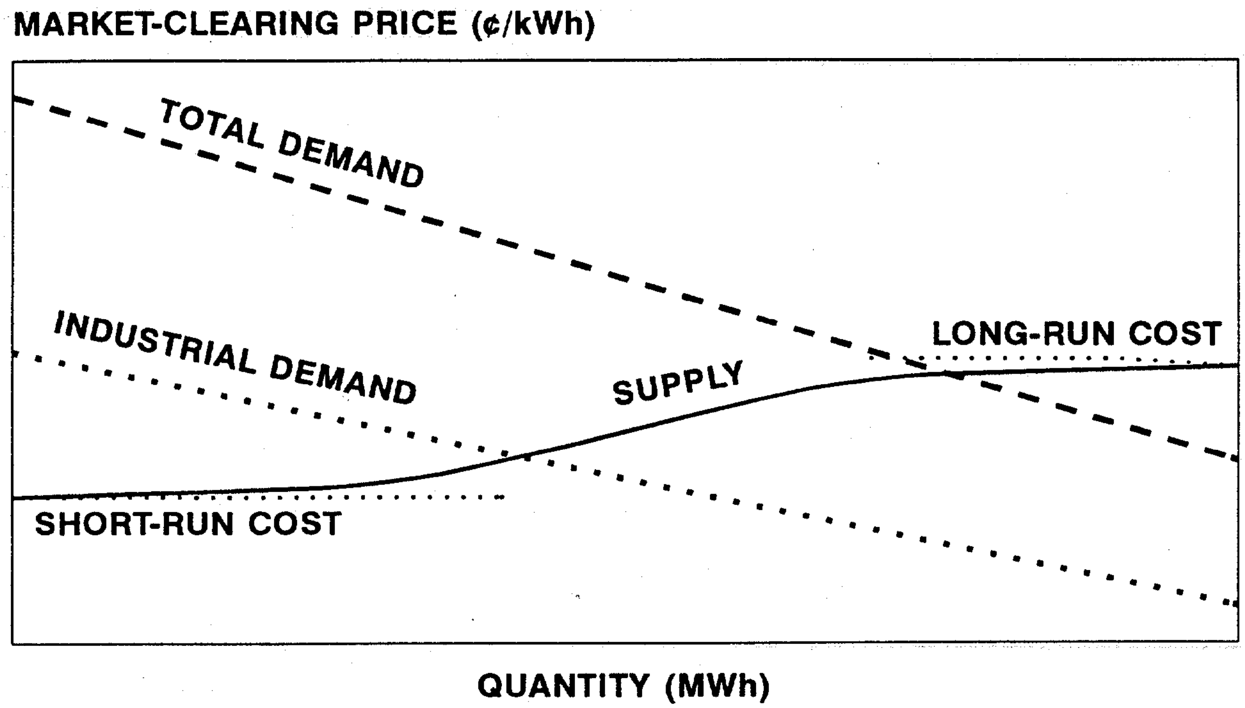

Fig. 1. **Relationships between supply and demand in determining the market price for electricity. At low levels of demand, the supply price will likely be close to the short-term operating cost of existing power plants. At high levels of demand, the price will approximate the capital plus operating cost of new power plants, assumed here to be gas-fired combined-cycle units.**

Table 1. The effects of income taxes on transforming revenue changes into changes in net income

Income statement items	Amount (million $) Base case	Price cut 10%	Comments
Electric revenues	1,698.1	1,528.3	Cut revenues $170 million
Expenses			
Fuel	381.8	381.8	
Purchased power	124.4	124.4	
O&M, fixed + variable	124.9	124.9	
Production expenses, total	631.2	631.2	
Nonproduction expenses	320.7	320.7	
Book depreciation	157.9	157.9	
Revenue sensitive taxes	50.9	45.8	Sales tax cut $5 million
Property taxes	75.7	75.7	
Federal income taxes, current	105.4	46.1	Income taxes cut $59 million
Federal income taxes, deferred	0.0	0.0	
Expenses, total	1,341.8	1,277.4	
Operating income	356.3	250.8	
Interest expense	168.9	168.9	
Net Income	187.4	82.0	Net income cut $105 million
Dividends	140.5	61.5	
Additions to retained earnings	46.8	20.5	

ALTERNATIVE WAYS TO COMPUTE STRANDED COMMITMENTS

San Diego Gas & Electric (1994) categorized methods to calculate SC along three dimensions: bottom-up vs top-down, ex ante vs ex post, and administrative vs market determination (Table 2).

Table 2. Alternative ways to compute stranded commitments

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

Source: San Diego Gas & Electric (1994).

To illustrate, a bottom-up, ex ante, administrative approach would involve calculation of the unit-by-unit performance of each of a utility's power plants in a hypothesized competitive generation market. Calculating the return provided by each generating unit involves detailed production-cost simulations for both the utility in question and the surrounding utilities and independent power producers. These simulations would show the number of hours each year that each unit operates, the market price of power that hour, and, from these numbers, the profitability of each unit. Such calculations require thousands of assumptions concerning present and future customer locations, loads, load shapes, and peak loads; transmission system operation, expansion, constraints, costs, and pricing rules; operating costs and performance of all existing and new generating units; fuel prices; government decisions on siting and environmental restrictions for new power plants and transmission lines; and so on. A bottom-up analysis requires similarly detailed calculations of stranded liabilities, regulatory assets, and public-policy programs. As San Diego Gas & Electric (1994) put it, "The essence of the [bottom-up] method is to work asset by asset [as well as liability by liability] to identify a market price and compare this price with the regulated cost of the asset [or liability]."

The top-down approach is the opposite of the bottom-up approach. The top-down approach, rather than using the individual asset as the unit of observation, treats the utility as the unit of observation. In the top-down, ex ante, administrative approach, which is the one we apply later, the embedded cost of electricity from each utility is compared with an assumed market price. This approach is much simpler than the bottom-up approach, primarily because it requires only a few assumptions and elementary calculations. However, it is also much less detailed and, therefore, provides fewer insights into the specific assets, liabilities, and costs that account for a utility's SC situation.

An ex ante approach determines the amount of stranded commitment before the transition to competition is conducted. An ex post approach determines the amount stranded after the transition is complete, based on actual market conditions. Although not explicit in the San Diego classification system, the ex ante approach is closely related to regulatory determination of the amount of SC, while the ex post approach is closely related to market determinations. To illustrate an ex ante approach, a state regulatory commission might conduct hearings to determine the amount and allocation of SC before approving a new industry structure (California Public Utilities Commission 1994). Alternatively, in an ex post approach, the commission could order a new structure in which the local utility sells all its power plants. The market price of these assets could then be compared to their book value in later determining the amount and allocation of SC.

Administrative determination involves agreement between the utility and the regulator (presumably the state public utility commission but, in some cases, the Federal Energy Regulatory Commission) on the amount that is stranded (FERC 1994). Market determination relies on the purchase price of various assets to determine how much is stranded.

The dollar value computed with any of these methods will depend on various factors, including the timing and scope of the transition to competition. If the transition occurs rapidly and affects all customer classes, the stranded costs will be much greater than if the transition occurs gradually over several years. The structure of the generation market and treatment of present and future power-purchase contracts will also affect the dollar estimates. Whether utilities can write up some or all of the value of their transmission assets (to offset losses associated with uneconomical generation assets) will affect the estimated costs of SC (Moskovitz and Foy 1994).

We found several recent analyses that used these alternative ways to compute SC. Anderson, Graham, and Hogan (1993) used a bottom-up method to calculate SC as a function of market prices for electricity. They computed the exposure associated with stranded assets (coal and nuclear power plants) for the Pennsylvania-New Jersey-Maryland (PJM) power pool as $11 billion for 1998 to 2002. This exposure is approximately equal to the utilities' book equity. This estimate is large because Anderson et al. assumed that the utilities would receive revenue only "from the marginal energy charge" with no capacity payments. In other words, utilities receive enough money to cover only variable (fuel plus operations and maintenance) costs, with no recovery of fixed costs.

Merrill Lynch (1994) used a top-down method to develop a competitive-risk matrix for electric utilities, based in part on the difference in industrial electricity price for a utility and the regional average price. McCullough and Brown (1994) calculated the amount of price increases that residential and commercial customers would face if industrial customers could purchase power at a price defined by a gas-fired CCCT. Moody's (1994), using a bottom-up approach, estimated the competitiveness of individual power plants in what it called the "Michigan Competitive Arena," an area that includes 13 investor-owned utilities (IOUs) in Michigan, Indiana, Ohio, Kentucky, and Illinois. Moody's calculated a market-clearing price and then calculated the margins (either positive or negative) that each plant would receive in that market. Rudden Associates (1994) used a bottom-up approach similar to the one used by Moody's to calculate marginal costs for generation in each North American Electric Reliability Council (NERC) region and subregion, using these market costs to determine the competitiveness of individual generating units.

Filings with the California Public Utilities Commission showed the diversity of approaches used to calculate SC and the range of results that can therefore occur. Pacific Gas and Electric (1994) calculated SC using "as a proxy for market prices, a range of 4¢/kWh plus or minus 20% for baseload generation." The company calculated SC assuming that the costs of utility-owned generation, qualifying-facility power-purchase obligations, and regulatory assets would be recovered over 6, 9, or 12 years. These costs ranged from $3 to 16 billion. The PUC's Division of Ratepayer Advocates and the Center for Energy Efficiency and Renewable Technologies, on the other hand, challenged many of the utility assumptions and developed estimates of SC that were much lower. Indeed, the Division of Ratepayer Advocates recommended a value of zero (Goldman and Belden 1994). These differences hinged on use of net vs gross SC; assumptions concerning market prices, utility costs, and the size of the markets at risk from competition; and the extent to which the utility could mitigate what would otherwise be SC.

ORNL METHOD

We developed and applied a top-down method to estimate the amounts of SC faced by individual IOUs. It is similar in principle to the methods developed by Merrill Lynch (1994) and by McCullough and Brown (1994).

Our method is based on the difference between the industrial electricity price for the utility in question and an estimated market price for the region as a whole. We tested two proxies for market price: (1) the capital and operating cost of a CCCT* and (2) a "capacity-adjusted" price that lies between the region's short-term operating cost and the cost of a CCCT based on the capacity margin in the region. We assume that this latter price equals the region's short-term operating cost if the region's capacity margin exceeds 20%, equals the region's cost of a CCCT if the region's capacity margin is below 15%, and varies linearly between these two levels for capacity margins between 15 and 20%.

For purposes of sensitivity analysis, we also tested two other prices: the average industrial electricity price in the region and the short-term operating cost of existing power plants. (The assumed short-run marginal cost is 2¢/kWh in each region.) The market price declines, and therefore the estimates of SC increase, as one moves from the industrial price to the short-term operating cost. Appendix Table A-1 shows the four sets of regional prices, and Table A-2 shows the details of CCCT capital and operating costs.

We used the nine NERC regions to define the boundaries of competitive electricity markets (Fig. 2). Although electricity flows across these boundaries, they seem like reasonable limits given the coordination and planning that occurs *within* each region.

We tested two assumptions concerning the fraction of a utility's retail load that would be at risk (i.e., able to obtain electricity supplies from a competitive regional market): (1) industrial customers only or (2) all retail customers. These alternatives probably bound the range of likely outcomes.

In both cases, we used the difference between the utility's average *industrial* price and the assumed regional market price as the relevant measure of SC. Industrial prices typically include

*For the industrial-only case, we assumed a capacity factor of 75%; for the all-retail case we assumed a capacity factor of 60% (Table A-2). These assumptions reflect the difference in load factors between the industrial class and other retail classes.

generation and transmission costs but no distribution-system costs and few customer-service costs. Thus, industrial price is a good proxy for the utility's ability to compete in wholesale markets. On the other hand, prices to residential and commercial customers include substantial costs not related to generation and transmission. Comparing prices that include many services with a generation-and-transmission-only market price would be inappropriate.

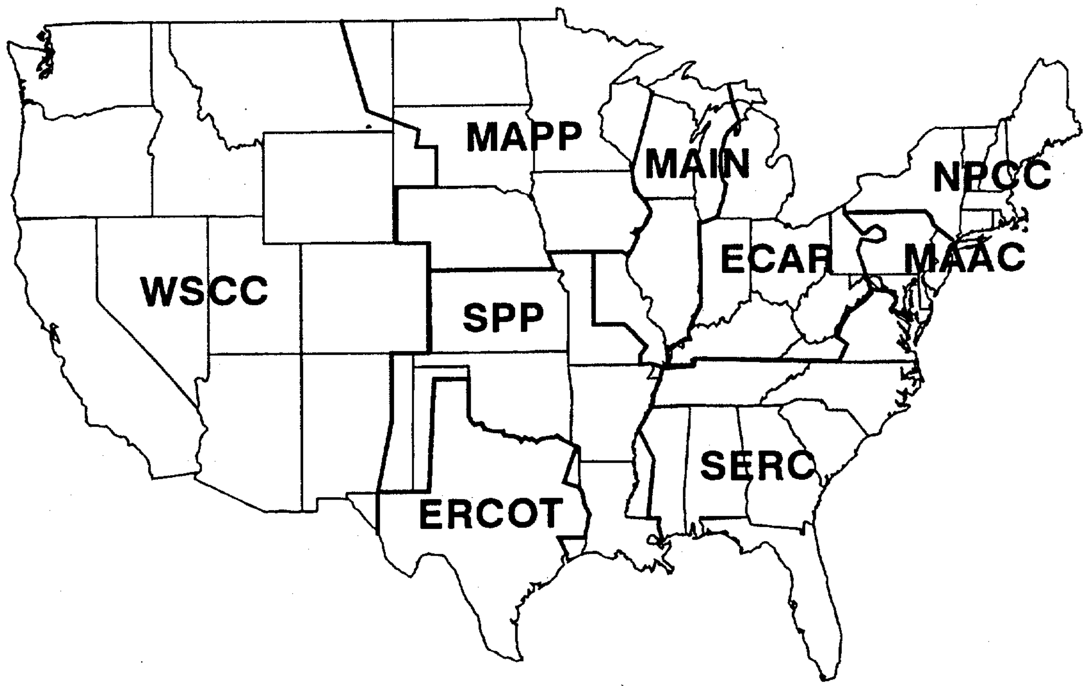

Fig. 2. Map of the United States showing the approximate boundaries of the nine NERC regions.

We added 0.44¢/kWh to the regional market prices to make them consistent with the utility's average industrial rate.* In a competitive environment, transmission owners will likely try to charge higher prices. For example, Detroit Edison's retail wheeling tariff proposes a charge of about 2.0¢/kWh for transmission and ancillary services (Musial 1994).#

Our method also requires assumptions concerning the number of years during which the price difference noted above persists, the appropriate discount rate to use in calculating the net present value (NPV) of this revenue loss, and the combined federal-state income tax rate.

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*This estimate is based on the 1992 embedded cost of transmission averaged over all large IOUs (EIA 1993). Transmission accounts for 6.2% of total utility costs, with costs allocated among generation, transmission, distribution, and customer service. The national average retail electricity price for all IOUs was 7.12¢/kWh in 1993 (EEI 1994). Then 0.062(7.12) = 0.44¢/kWh.

#The Michigan Public Service Commission (1994), commenting on the "wide disparity in pricing" of transmission services, cited estimates of transmission and other wheeling costs ranging from 0.4 to 4.2¢/kWh.

To illustrate our method, consider a utility whose industrial customers are free to choose alternate suppliers. If the utility's average industrial price exceeded the regional market price, that utility would have to cut its price to all industrial customers to the market price to maintain market share. In other words, the utility's annual revenues would be cut by the product of its industrial sales and this difference in electricity price. If this difference persists unchanged (in constant-dollar terms) for ten years, then the amount of SC would equal the net present value of the after-tax ten-year revenue loss. During this time, the utility would likely reduce its costs (e.g., by cutting staff and renegotiating fuel-supply and power-purchase contracts). In addition, depreciation would reduce the amount of uneconomical (i.e., expensive) capacity that the utility has on its books. We ignore these possibilities.

We used data for 1992 and 1993 that utilities report to the Energy Information Administration on EIA-861 and to the Federal Energy Regulatory Commission (FERC) on FERC-1(EIA 1994a and Edison Electric Institute 1994). These data include retail sales, revenues, and prices by customer class, as well as the utility's equity [specifically, the value of its common stock, preferred stock, retained earnings, and several smaller items, which in total are called total proprietary capital (EIA 1993)].

The 160 utilities included in our database account for virtually all of the 1992 industrial sales and revenues by the 180 major IOUs included in the EIA (1993) report. We used the Electric Power Research Institute's *Technical Assessment Guide* to calculate the cost of a combined-cycle unit (EPRI 1993); see Table A-2. We used state-level data on the prices that electric utilities paid for natural gas to compute the operating cost of a CCCT for each NERC region (Edison Electric Institute 1993). And we used projections developed by the North American Electric Reliability Council (1994) of capacity margins to the year 2003 (Table A-13).

We calculated market electricity prices for each of the nine NERC regions in the contiguous United States (Figs. 2 and 3). We then compared the values of industrial electricity price and the regional average for each of the 160 major IOUs in our database. Thus, we assume that competition is much more likely within each region than between regions. If the utility's price exceeded the regional average, we computed an annual revenue loss as:

$$\text{Revenue loss (\$/year)} = \Delta\text{Industrial price (¢/kWh)} \times \text{Industrial sales (GWh/year)} \ ,$$

where ΔIndustrial price = 0 if $P_{utility} < P_{region}$ and $= P_{utility} - P_{region}$ if $P_{utility} > P_{region}$.

We assumed that this revenue loss (in real dollars) would persist for ten years. We computed the NPV of this annual loss for the ten-year period with a real discount rate of 8%. This discount rate is equivalent to a return on equity of 11 to 12% and an annual inflation rate of 3 to 4%. Our assumed return on equity is consistent with current figures compiled by Merrill Lynch (Cohen et al. 1994). Finally, we reduced the amount of this loss because taxpayers (through federal and income taxes) would pay for about 35% of these totals. In Chapter 5, we present sensitivity analyses, in which we varied the discount rate, the number of years, the competitive-market price (up or down from the NERC-region average), and the share of retail load at risk.

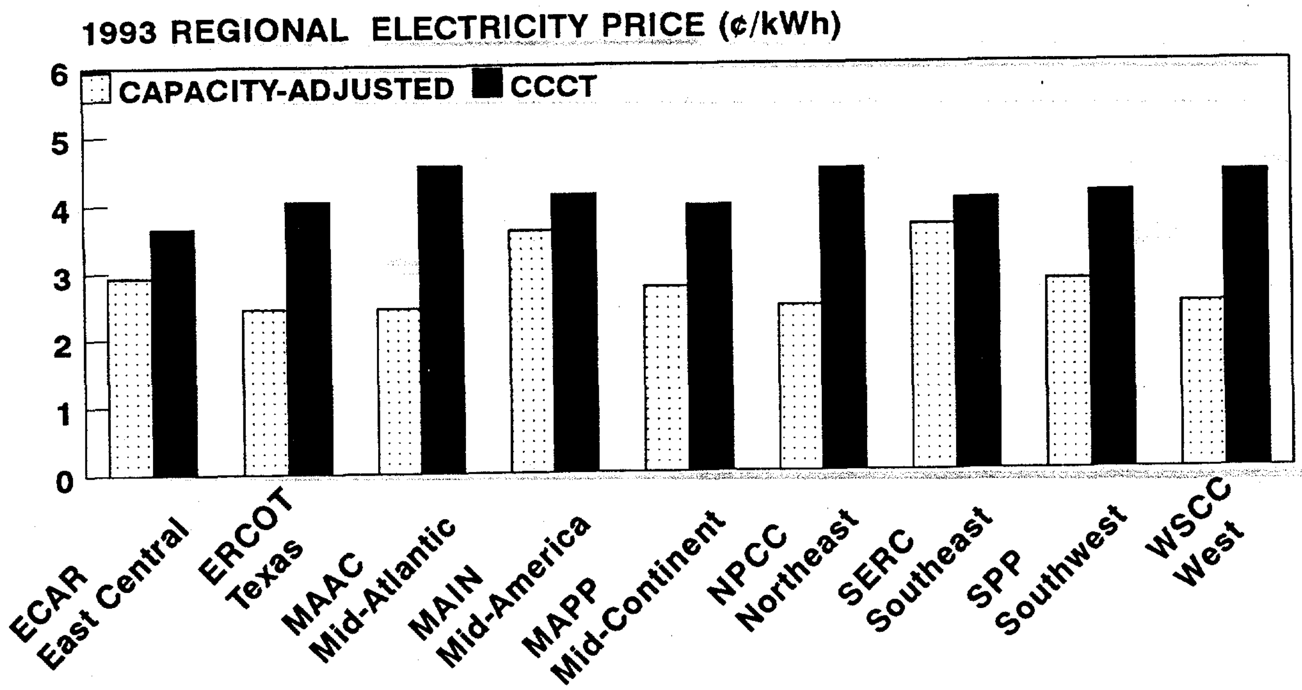

Fig. 3. **Alternative estimates of regional market electricity prices by NERC region. (See Table A-1 for details on all four sets of assumed regional market prices.)**

RESULTS

Among individual utilities, industrial prices in 1993 ranged from less than 2¢/kWh to more than 10¢/kWh. Across the nine NERC regions, average industrial prices ranged from 4.2¢/kWh in MAPP to 7.4¢/kWh in NPCC. The regional variation in CCCT prices was less, ranging from 3.6¢/kWh in ECAR to 4.6¢/kWh in MAAC (Fig. 3). And the capacity-adjusted price ranged from 2.4¢/kWh in ERCOT, MAAC, NPCC, and WSCC (where capacity margins are all above 20%) to 3.6¢/kWh in MAIN and SERC (where capacity margins are only about 16%). Because of these large price differences, both across individual utilities and across regions, a substantial amount of revenue could be "lost" for those utilities with prices higher than the regional market price.

The results presented below assume that the revenue loss continues unchanged in real dollars for ten years with the NPV of the revenue loss calculated at a real discount rate of 8%.

Consider first the industrial sector only. As the assumed market price of power declines from the regional industrial price to the CCCT price, capacity adjusted price, and the short-run marginal cost, the amount of SC increases (Table 3), ranging from 8% to 45% of the equity held by all the major U.S. IOUs. To take what we consider to be a reasonable example, consider the case where industrial customers can obtain electricity at the capacity-adjusted price (Table A-3). Overall, 77% of U.S. IOU industrial sales would be affected, equivalent to 711,000 GWh/year, leading to an annual revenue loss of $15.8 billion. The NPV of the associated after-tax earnings loss is $68.8 billion, which represents 38% of IOU equity.

If all retail customers (residential, commercial, and industrial) are able to obtain electricity at market prices, the amounts of stranded commitment are larger, ranging from 21% to 140% of utility equity (Table 3). However, as noted above, we think it is unrealistic to match a large demand with a very low price (and vice versa). Thus, we think that competition that allows only the industrial class to access competitive generation markets will yield low market prices (i.e., the right side of the Industrial-only line in Table 3). On the other hand, if industry restructuring allows all retail customers to obtain market-priced power, that price will be higher (i.e., the left side of the All-retail line in Table 3). For the case with all retail load at risk and the market price based on the cost of a CCCT, SC amounts to $99 billion for the ten years, equivalent to 54% of IOU equity (Table A-8).

These results suggest that utilities might be at risk for 38 to 54% of their equity, based on the industrial-only/capacity-adjusted price and the all-retail/CCCT price cases. These two cases show substantial differences across NERC regions (Fig. 4).

Table 3. Potential stranded commitment in billions of 1992 dollars (and as percent of equity) as a function of portion of load at risk and market price of generation

	Market price[a]			
Portion of load at risk	Industrial average	Combined-cycle turbine	Capacity adjusted	Short-run marginal cost
Industrial only	15 (8%)	34 (19%)	69 (38%)	83 (45%)
All retail	39 (21%)	99 (54%)	210 (115%)	256 (140%)

[a]The assumed market prices decline from left to right.

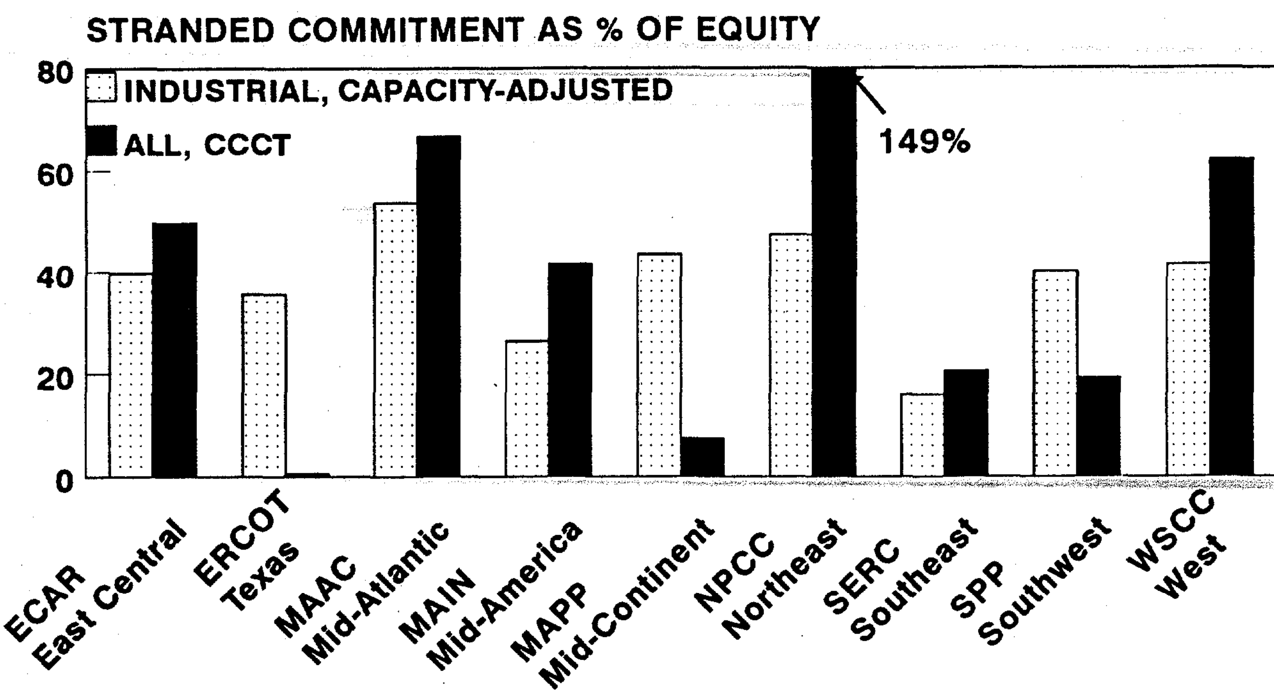

Fig. 4. Potential stranded commitments normalized by equity for the nine NERC regions in the contiguous United States. (Tables A-3 and A-8 show the details for these two cases.)

For the industrial-only/capacity-adjusted-price case (dotted bars in Figs. 3 and 4), losses are highest in MAAC (54% of IOU equity would be stranded with these assumptions) and lowest in SERC (16%). The market price in MAAC (as well as in ERCOT, NPCC, and WSCC) is quite low because of high capacity margins (Tables A-1 and A-13). This low market price combined with the high industrial prices of many utilities in MAAC (as well as in NPCC) leads to large losses (Table A-3). On the other hand, the market price in SERC is high because capacity margins in that region are low. And industrial prices are low in SERC, further reducing the SC in this case.

Altogether, 153 utilities (of the 160 IOUs examined) face some SC in this case. Of these, 17 have SC that exceed 100% of their equity, and another 120 have SC between 10 and 100% of equity. Twenty utilities have potential losses of $1 billion or more. These utilities are concentrated in a few states, including California, Pennsylvania, Texas, New York, and Ohio in declining order of importance. Losses exceed 50% of utility equity in 13 states (left side of Table 4).

Table 4. States in which stranded commitments might exceed 50% of utility equity

Industrial only, Capacity-adjusted price		All retail, Combined-cycle price	
State	% of equity stranded	State	% of equity stranded
Rhode Island	142	Rhode Island	405
Maine	113	Massachusetts	230
New Hampshire	109	New Hampshire	179
Massachusetts	71	Connecticut	170
Nevada	62	New York	139
Arkansas	58	Maine	119
Pennsylvania	56	New Jersey	117
Minnesota	55	California	99
Connecticut	55	Mississippi	97
California	53	Michigan	88
Maryland	52	Arizona	76
Michigan	52	Arkansas	63
Louisiana	51	Illinois	61
		Ohio	60
		New Mexico	60
		Pennsylvania	52

For the all-retail/CCCT price case (solid bars in Figs. 3 and 4), the total amount of SC is larger than for the industrial-only/capacity-adjusted price case considered above (54 vs 38% of equity). By far, the largest losses occur in NPCC (149% of equity). Losses are less than 10% in

ERCOT and MAPP. The potential losses are so large in NPCC because the retail load at risk is much larger than in most regions and because the industrial price is the highest among all regions (Table A-8). Losses are low in ERCOT and MAPP because both industrial prices and the amount of load at risk are low.

Altogether, 100 utilities face some SC in this case. Of these, 36 have SC that exceed 100% of their equity, and another 53 have SC between 10 and 100% of equity. Twenty-five utilities have potential losses of $1 billion or more. These utilities are concentrated in a few states, including New York, California, New Jersey, Massachusetts, Ohio, and Pennsylvania in declining order of importance. Lost revenues exceed 50% of utility equity in 16 states (right side of Table 4).

Estimates of SC losses are higher for the all-retail case than for the industrial-only case, as expected, in six of the nine NERC regions (Fig. 4). SC losses are higher in the industrial-only case for the other three regions. In ERCOT, the amount of sales "lost" in the all-retail case is very small because the industrial price for most utilities is below that of the CCCT, although far above that of the capacity-adjusted price. In MAPP, the amount of sales lost is about the same in both cases, but the price difference is much greater in the industrial-only case. And in SPP, the amount of sales lost is greater in the all-retail case, but the price difference is so much larger in the industrial-only case that the SC losses are greater in the latter case.

In both cases, the potential SC losses are especially severe in California, New York, Ohio, and Pennsylvania. Relative to the amount of utility equity, losses could be largest in several New England states (Maine, Massachusetts, New Hampshire, and Rhode Island).

As noted earlier, the amount of SC depends strongly on the assumptions made. The key assumptions are the market price of electricity and the fraction of retail load lost. Figure 5 shows the importance of these factors. At any market price, the loss to utility shareholders is 2.5 to 3 times as great when all retail loads are at risk than when only industrial loads are at risk. Raising the assumed market price of electricity by 1¢/kWh decreases the equity loss by 25 percentage points for all retail customers and by 10 percentage points for the industrial class only. Lowering the market price by 1¢/kWh increases the equity loss by 33 and 14 percentage points, respectively.* For the all-retail case, the change in stranded commitments is about $60 billion for every 1.0¢/kWh change in the market price of electricity. (Tables A-6 and A-7 show detailed results for cases in which industrial sales are at risk and the market price is the capacity-adjusted price ±1¢/kWh. Tables A-11 and A-12 show detailed results for cases in which all retail sales are at risk and the market price is the CCCT price ±1¢/kWh.)

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*This asymmetry occurs because the amount of SC depends on the *difference* between the utility's price and the market price, but only if the utility's price is *above* the market price. A 1¢/kWh increase in market price, for example, would reduce both the price difference and the number of utilities that face SC in a nonlinear fashion.

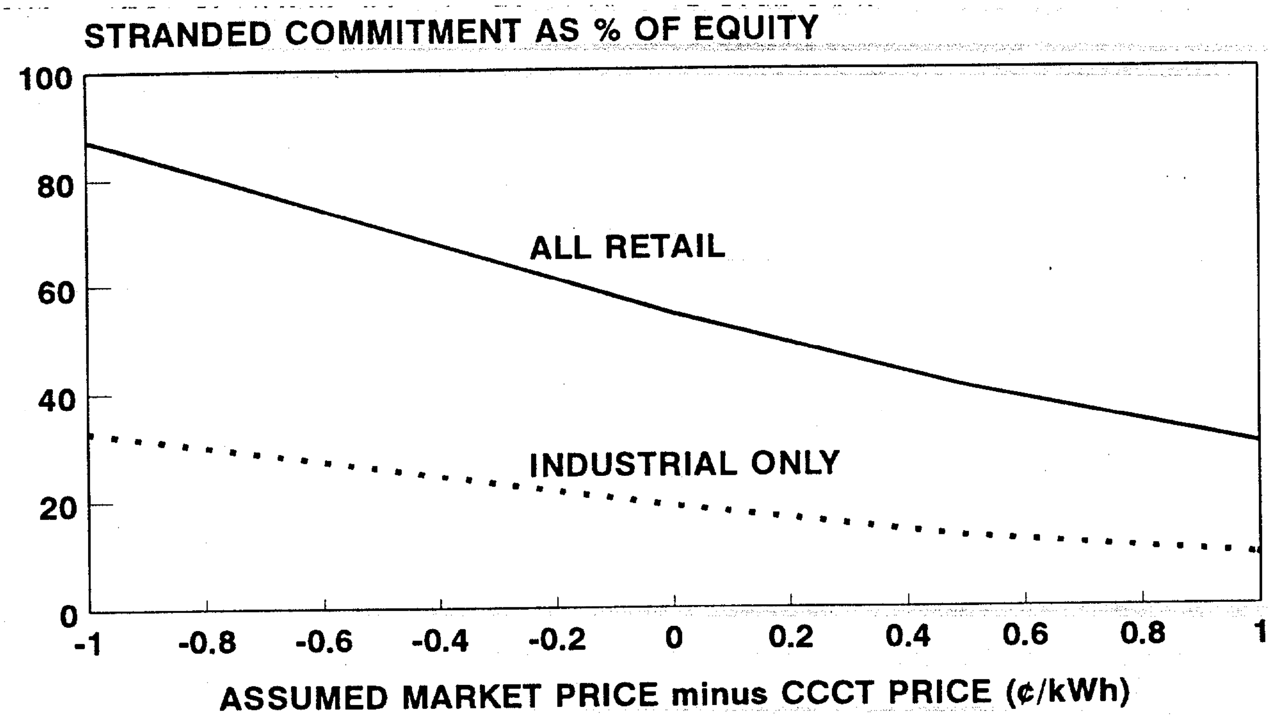

Fig. 5. Amount of stranded commitment for U.S. investor-owned electric utilities as a function of assumed market price (relative to the cost of a combined-cycle unit) and the amount of retail load at risk.

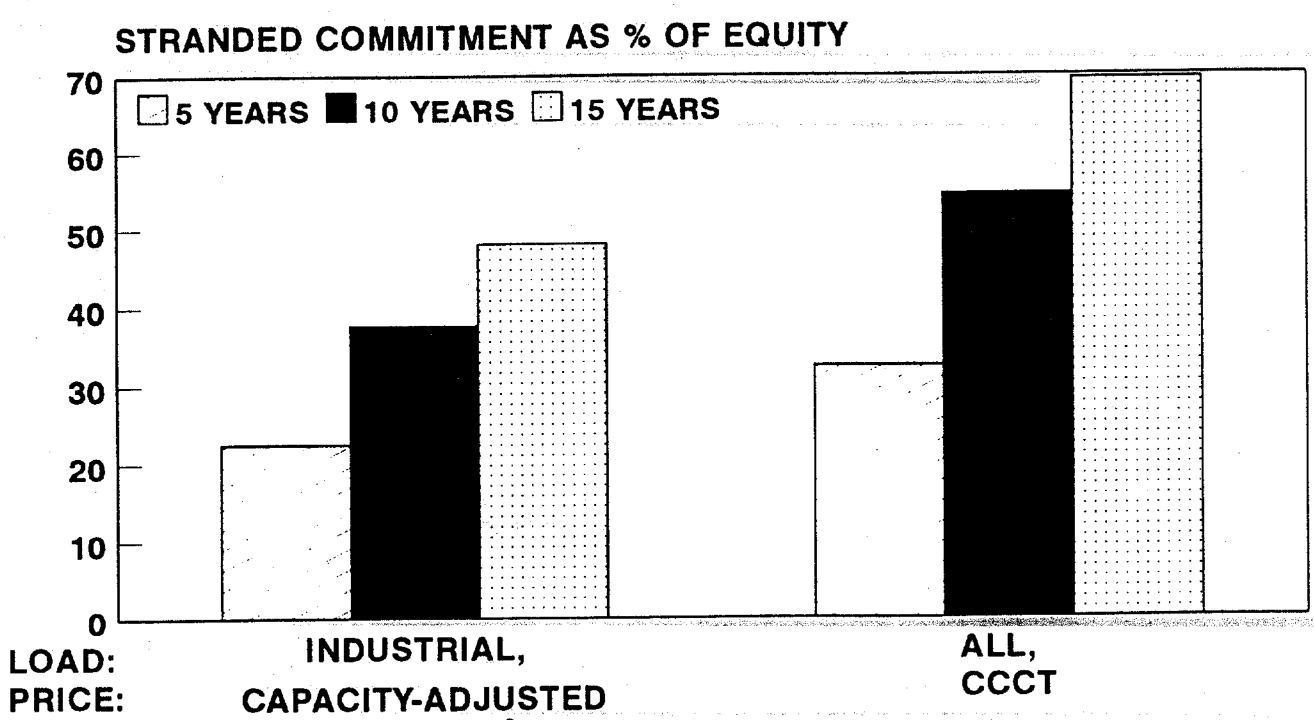

Fig. 6. Amount of stranded commitment for U.S. investor-owned electric utilities as a function of the years of loss and the amount of retail load at risk.

Another key assumption that affects results is the number of years over which the utility loses this revenue. If the revenue loss would occur for only five years (rather than the ten years assumed above), the equity loss would be cut by 40% (Fig. 6). On the other hand, if the revenue loss were to occur for 15 years, then the equity loss would increase by almost 30%. The asymmetry around ten years is a consequence of discounting. (Tables A-3 through A-5 show details for the cases in which industrial sales are at risk for 10, 15, or 5 years. Tables A-8 through A-10 show the comparable cases in which all retail sales are at risk.

Next, we varied the discount rate to see its effect on estimates of SC. Decreasing the real discount rate from 8 to 5% increases the amount of SC by 15%, while increasing the discount rate to 11% cuts the amount of SC by 12%. These results show that the discount rate has less effect on results than does the number of years that the lost revenues occur. Both factors are less important than the market price and fraction of retail load able to obtain market-priced electricity.

Finally, we ran a case in which the fraction of utility retail markets at risk, the market price of power, and utility prices all vary from year to year. Specifically, we assumed that in 1993 all industrial customers were free to choose their suppliers. For the next four years, increasing fractions of the remaining retail customers are offered such choices so that in 1997 all retail customers have access to alternate suppliers. We assumed that the utility, through vigorous cost-cutting efforts, is able to reduce its industrial electricity price each year by 2% of the 1993 price. We assumed that natural gas prices increase linearly by 2% of the regional 1993 price. Finally, we assumed that the capacity-adjusted price that industrial customers face increases as capacity margins decrease from year to year (Table A-13). These assumptions yield national estimates of SC that first increase while the share of retail sales that is eligible grows and then declines from year to year, as shown in Fig. 7. The earnings loss in 1994 and 1995 is $10.9 billion, declining to only $1.1 billion in the year 2009. The NPV of these losses is about $66 billion, which is within the range of results presented above (Table 3).

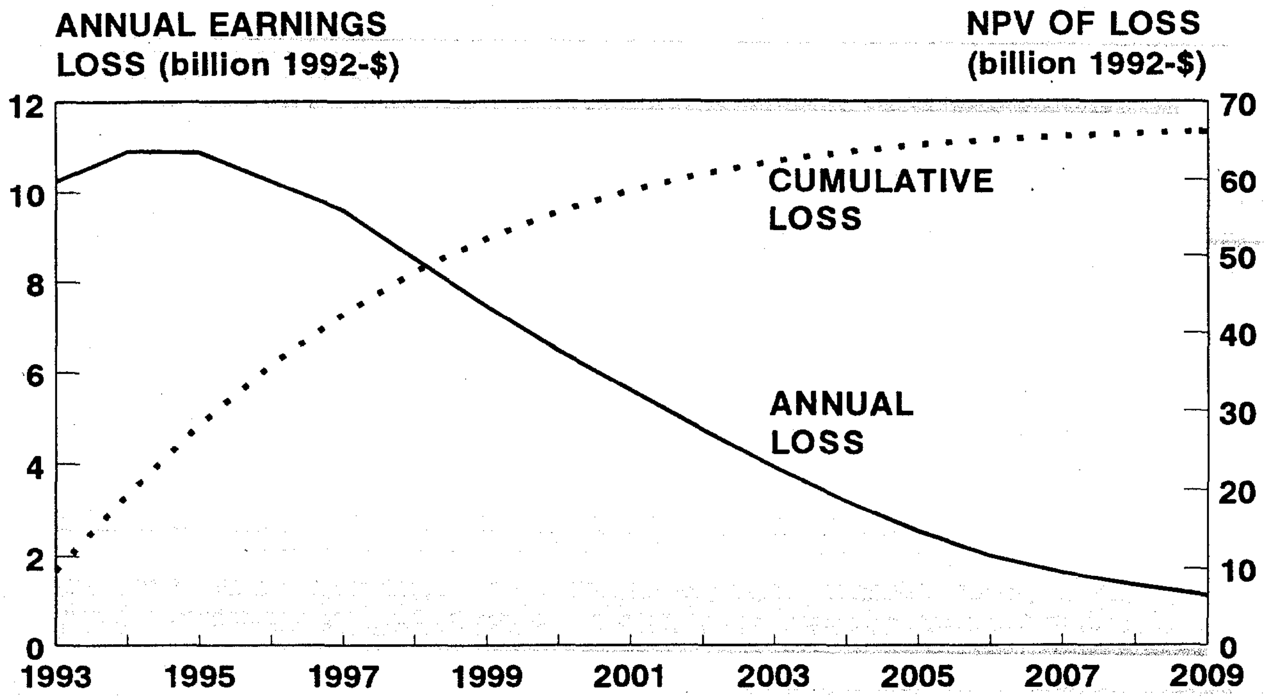

Fig. 7. **Annual and cumulative earnings losses for U.S. electric utilities over time assuming dynamic changes in retail markets at risk, the market price of electricity, and utility costs.**

OUR ASSUMPTIONS AND THEIR VALIDITY

Our method for calculating stranded commitment is very simple. It ignores all the details of the capital and operating costs of individual power plants, the differences in state and local taxes across utilities, customer load shapes and locations, and transmission and distribution costs, as well as many other factors. Our approach is a simple top-down method that abstracts from all these details.

Our key assumptions are:

- That this static analysis captures the dynamics of market forces reasonably well. For example, we ignore the feedback between lower electricity prices and higher electricity consumption (the price-elasticity effect). We are unsure whether increased consumption would benefit the local utility or its competitors. More generally, changes over time in electricity consumption and demand, in fuel prices, and in other factors will affect the amount of SC a utility faces. For example, the EIA (1994b) projects a roughly 3%/year increase in the real price of natural gas to electric utilities between 1992 and 2000.

- That the *net* SC calculated here is the appropriate measure of the potential losses to utility shareholders (or core customers) from retail wheeling. Net SC differs from *gross* SC, which ignores assets and contracts that have market values greater than book values.

- That losses in wholesale-power transactions and any associated stranded commitments can be ignored. The FERC (1994) estimates that 85 to 90% of SC are associated with retail service.

- That each utility's average industrial price accurately reflects the situation facing industrial customers. Although this price includes special rates for some customers (e.g., interruptible rates that are not interrupted and economic-development rates intended to provide discounts) and higher rates for others, it is a reasonable average. Our analysis, however, does not require that each utility's average industrial *price* accurately reflect the utility's *cost* to serve industrial customers. For example, if industrial prices are higher than costs because industrial customers subsidize residential customers, the associated loss of revenue will not be recovered from other customers and will constitute a stranded public-policy program.

- That the appropriate market for the retail customers of an individual utility includes other suppliers within that NERC region. We ignore opportunities to trade across the NERC-region boundaries; thus, we assume that transmission costs and losses to obtain supplies from outside that region would raise the price enough to make such transactions uneconomical.

- That the effects of future liabilities not presently in rates are small and are offset by other factors not included in our analysis. In some cases, these liabilities (especially those associated with long-term purchased-power contracts) are large.

- That the appropriate competitive electricity price is the average across a NERC region, and that ignoring time-of-use variations in production costs, transmission constraints, and retail prices introduces no major errors into this analysis.

- That the annual revenue loss associated with selling electricity to customers at the lower regional price translates dollar for dollar into lower pre-tax earnings. In other words, there are no offsetting operating-cost reductions.

- That an appropriate measure of SC is the net present value of the annual earnings loss, which is assumed to continue unchanged for a set number of years. More generally, we assume that the revenue *flows* of a utility's income statement can be translated directly into the capital *stocks* of its balance sheet.

- That the appropriate discount rate to use in the NPV calculation is the utility's real return on equity.

As part of our continuing work on this project, we will examine closely the effects that these assumptions could have on estimates of stranded commitments. Below are our current thoughts on the possible effects of those assumptions for which we can now hazard a guess. Considering the dynamics of utility, customer, and wholesale-market behaviors will likely lower estimates of SC. Calculating net (vs gross) estimates and adjusting for income taxes leads—correctly—to lower estimates of SC than would (incorrect) calculations that ignore these two factors. Neglecting possible wholesale losses and future liabilities (e.g., deferred income taxes) would underestimate SC. Ignoring the possibility of sales across the boundaries of NERC regions would underestimate SC; on the other hand, the costs and losses associated with long-distance transactions may exceed the 0.44¢/kWh factor we assumed.

CONCLUSIONS

We developed a rudimentary top-down method to estimate the amount of stranded commitment that each large U.S. investor-owned utility might face as of 1993. Our best estimates of SC range from 38% of utility equity ($69 billion) to 54% of equity ($99 billion). However, even this broad range is subject to considerable uncertainty. Roughly speaking, every 1¢/kWh change in the market price of electricity causes up to a $59 billion change in the amount of SC nationwide. The states with the biggest potential dollar losses include California, New York, Ohio, and Pennsylvania. The states with the biggest potential percentage losses include Maine, Massachusetts, New Hampshire, and Rhode Island.

Our analyses point to four major conclusions:

- Reported estimates of SC depend strongly on the assumptions made in deriving those numbers. Treat skeptically those estimates that are not well documented.
- The most important assumptions are the fraction of a utility's retail load that can obtain electricity supplies in a competitive market and the price of electricity in that competitive market. In addition, the number of years during which the utility suffers this revenue loss is an important determinant of results. Of course, these three sets of assumptions are related to each other.
- The appropriate measure of SC is the net, not the gross, estimate. The net estimate adjusts for utility assets that have a market value above book value.
- Estimates of SC should reflect the effects of federal and state income taxes, which serve to reduce the losses that utility shareholders and customers will ultimately have to absorb.

The amounts of stranded commitment computed here are large both in absolute terms and relative to utility shareholder equity. Developing reasonable and equitable ways to quantify, mitigate, and allocate these costs will likely be a critical precondition to restructuring the U.S. electricity industry.

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APPENDIX: DETAILED TABLES

Table A-1. Four sets of estimates of wholesale electricity prices by NERC region

NERC region	Alternative estimates of wholesale-market electricity prices (¢/kWh)			
	Average industrial price	Combined-cycle price[a]	Capacity-adjusted price[a]	Short-term price[a]
ECAR	4.26	3.65	2.93	2.44
ERCOT	4.39	4.03	2.44	2.44
MAAC	6.59	4.55	2.44	2.44
MAIN	4.49	4.13	3.59	2.44
MAPP	4.24	3.95	2.74	2.44
NPCC	7.41	4.46	2.44	2.44
SERC	4.67	4.01	3.63	2.44
SPP	4.48	4.09	2.80	2.44
WSCC	5.35	4.37	2.44	2.44
U.S. average	4.92	4.17	2.47	2.44

[a]These prices include a 0.44¢/kWh adder for transmission. The average industrial price implicitly includes transmission costs.

Table A-2. Estimates of capital and operating costs for a gas-fired combined-cycle combustion turbine

Capital Costs	
Total cost, \$/kW	595
Unit life, years	30
Discount rate, %	10
Operating Costs	
Fixed O&M, \$/kW-yr	26.5
Variable O&M, c/kWh	0.4
Heat rate, Btu/kWh	7,520
Fuel cost, \$/MBtu	2.61
Fuel cost, c/kWh	1.96
Capacity factor, %[a]	75
Total Costs, ¢/kWh	
Operating	2.77
Capital	0.96
Total	3.73

[a]For the all-retail case, we set the capacity factor at 60%.
Source: Electric Power Research Institute (1993).

Table A-3. Details of stranded-commitments calculation for the case in which only industrial sales are at risk, the market price is the capacity-adjusted price, and losses occur for ten years

NERC region	Sales loss (TWh/ year)	Revenue loss (billion \$/year)	Earnings loss (billion \$/year)	NPV of earnings loss (billion \$)	Equity (billion \$)	Percent of equity lost
ECAR	151.9	2.4	1.6	10.6	26.7	39.7
ERCOT	61.8	1.1	0.7	5.0	14.0	35.6
MAAC	69.2	2.9	1.9	12.5	23.2	53.7
MAIN	60.8	0.9	0.6	3.7	14.1	26.3
MAPP	37.4	0.6	0.4	2.4	5.5	43.5
NPCC	47.2	2.6	1.7	11.4	24.1	47.4
SERC	111.4	1.1	0.7	4.8	29.8	16.0
SPP	75.8	1.3	0.8	5.5	13.7	40.1
WSCC	95.0	3.0	1.9	12.9	31.0	41.6
Totals	710.5	15.8	10.2	68.8	182.1	37.7

Table A-4. **Details of stranded-commitments calculation for the case in which only industrial sales are at risk, the market price is the capacity-adjusted price, and losses occur for 15 years**

NERC region	Sales loss (TWh/ year)	Revenue loss (billion $/year)	Earnings loss (billion $/year)	NPV of earnings loss (billion $)	Percent of equity lost
ECAR	151.9	2.4	1.6	13.6	50.7
ERCOT	61.8	1.1	0.7	6.3	45.4
MAAC	69.2	2.9	1.9	15.9	68.5
MAIN	60.8	0.9	0.6	4.7	33.6
MAPP	37.4	0.6	0.4	3.1	55.5
NPCC	47.2	2.6	1.7	14.6	60.5
SERC	111.4	1.1	0.7	6.1	20.4
SPP	75.8	1.3	0.8	7.0	51.2
WSCC	95.0	3.0	1.9	16.4	53.1
Totals	710.5	15.8	10.2	87.7	48.2

Table A-5. **Details of stranded-commitments calculation for the case in which only industrial sales are at risk, the market price is the capacity-adjusted price, and losses occur for 5 years**

NERC region	Sales loss (TWh/ year)	Revenue loss (billion $/year)	Earnings loss (billion $/year)	NPV of earnings loss (billion $)	Percent of equity lost
ECAR	151.9	2.4	1.6	6.3	23.6
ERCOT	61.8	1.1	0.7	3.0	21.2
MAAC	69.2	2.9	1.9	7.4	32.0
MAIN	60.8	0.9	0.6	2.2	15.7
MAPP	37.4	0.6	0.4	1.4	25.9
NPCC	47.2	2.6	1.7	6.8	28.2
SERC	111.4	1.1	0.7	2.8	9.5
SPP	75.8	1.3	0.8	3.3	23.9
WSCC	95.0	3.0	1.9	7.7	24.8
Totals	710.5	15.8	10.2	40.9	22.5

Table A-6. Details of stranded-commitments calculation for the case in which only industrial sales are at risk, the market price is the capacity-adjusted price plus 1¢/kWh, and losses occur for ten years

NERC region	Sales loss (TWh/ year)	Revenue loss (billion $/year)	Earnings loss (billion $/year)	NPV of earnings loss (billion $)	Percent of equity lost
ECAR	151.9	1.2	0.8	5.3	19.7
ERCOT	61.8	0.5	0.3	2.3	16.3
MAAC	69.2	2.2	1.4	9.5	40.7
MAIN	60.8	0.4	0.3	1.7	12.3
MAPP	37.4	0.2	0.1	0.8	14
NPCC	47.2	2.1	1.4	9.4	38.8
SERC	111.4	0.2	0.1	0.7	2.5
SPP	75.8	0.5	0.3	2.3	16.9
WSCC	95.0	2.0	1.3	8.9	28.8
Totals	710.5	9.4	6.1	40.8	22.4

Table A-7. Details of stranded-commitments calculation for the case in which only industrial sales are at risk, the market price is the capacity-adjusted price minus 1¢/kWh, and losses occur for ten years

NERC region	Sales loss (TWh/ year)	Revenue loss (billion $/year)	Earnings loss (billion $/year)	NPV of earnings loss (billion $)	Percent of equity lost
ECAR	151.9	4.0	2.6	17.2	64.5
ERCOT	61.8	1.8	1.1	7.7	54.9
MAAC	69.2	3.6	2.3	15.5	66.7
MAIN	60.8	1.5	0.9	6.4	45.1
MAPP	37.4	0.9	0.6	4.0	73.1
NPCC	47.2	3.1	2.0	13.5	55.9
SERC	111.4	2.2	1.4	9.6	32.3
SPP	75.8	2.0	1.3	8.8	64.3
WSCC	95.0	3.9	2.5	17.0	55.0
Totals	710.5	22.9	14.9	99.7	54.8

Table A-8. Details of stranded-commitments calculation for the case in which all retail sales are at risk, the market price is the combined-cycle unit cost, and losses occur for ten years

NERC region	Sales loss (TWh/ year)	Revenue loss (billion $/year)	Earnings loss (billion $/year)	NPV of earnings loss (billion $)	Percent of equity lost
ECAR	250.9	3.1	2.0	13.3	49.8
ERCOT	7.2	0.0	0.0	0.1	0.6
MAAC	201.1	3.6	2.3	15.5	66.8
MAIN	115.6	1.3	0.9	5.9	41.7
MAPP	37.9	0.1	0.1	0.4	7.3
NPCC	209.0	8.2	5.4	36.0	149.3
SERC	244.7	1.4	0.9	6.1	20.6
SPP	97.1	0.6	0.4	2.6	19.2
WSCC	205.8	4.4	2.9	19.2	62.1
Totals	1369.4	22.7	14.8	99.2	54.5

Table A-9. Details of stranded-commitments calculation for the case in which all retail sales are at risk, the market price is the combined-cycle unit cost, and losses occur for 15 years

NERC region	Sales loss (TWh/ year)	Revenue loss (billion $/year)	Earnings loss (billion $/year)	NPV of earnings loss (billion $)	Percent of equity lost
ECAR	250.9	3.1	2.0	17.0	63.5
ERCOT	7.2	0.0	0.0	0.1	0.8
MAAC	201.1	3.6	2.3	19.8	85.2
MAIN	115.6	1.3	0.9	7.5	53.1
MAPP	37.9	0.1	0.1	0.5	9.4
NPCC	209.0	8.2	5.4	45.9	190.4
SERC	244.7	1.4	0.9	7.8	26.3
SPP	97.1	0.6	0.4	3.3	24.5
WSCC	205.8	4.4	2.9	24.5	79.2
Totals	1369.4	22.7	14.8	126.5	69.5

Table A-10. Details of stranded-commitments calculation for the case in which all retail sales are at risk, the market price is the combined-cycle unit cost, and losses occur for 5 years

NERC region	Sales loss (TWh/ year)	Revenue loss (billion $/year)	Earnings loss (billion $/year)	NPV of earnings loss (billion $)	Percent of equity lost
ECAR	250.9	3.1	2.0	7.9	29.6
ERCOT	7.2	0.0	0.0	0.1	0.4
MAAC	201.1	3.6	2.3	9.2	39.8
MAIN	115.6	1.3	0.9	3.5	24.8
MAPP	37.9	0.1	0.1	0.2	4.4
NPCC	209.0	8.2	5.4	21.4	88.8
SERC	244.7	1.4	0.9	3.7	12.3
SPP	97.1	0.6	0.4	1.6	11.4
WSCC	205.8	4.4	2.9	11.4	37.0
Totals	1369.4	22.7	14.8	59.0	32.4

Table A-11. Details of stranded-commitments calculation for the case in which all retail sales are at risk, the market price is the combined-cycle unit cost plus 1¢/kWh, and losses occur for ten years

NERC region	Sales loss (TWh/ year)	Revenue loss (billion $/year)	Earnings loss (billion $/year)	NPV of earnings loss (billion $)	Percent of equity lost
ECAR	250.9	1.2	0.8	5.1	19.1
ERCOT	7.2	0.0	0.0	0.0	0.1
MAAC	201.1	1.8	1.2	8.0	34.3
MAIN	115.6	0.5	0.4	2.4	16.9
MAPP	37.9	0.0	0.0	0.0	0.0
NPCC	209.0	6.3	4.1	27.6	114.4
SERC	244.7	0.0	0.0	0.1	0.4
SPP	97.1	0.2	0.1	0.8	5.5
WSCC	205.8	2.4	1.6	10.5	33.8
Totals	1369.4	12.5	8.1	54.4	29.9

Table A-12. Details of stranded-commitments calculation for the case in which all retail sales are at risk, the market price is the combined-cycle unit cost minus 1¢/kWh, and losses occur for ten years

NERC region	Sales loss (TWh/ year)	Revenue loss (billion $/year)	Earnings loss (billion $/year)	NPV of earnings loss (billion $)	Percent of equity lost
ECAR	250.9	5.6	3.6	24.3	90.7
ERCOT	7.2	0.1	0.1	0.4	2.9
MAAC	201.1	5.6	3.6	24.3	104.6
MAIN	115.6	2.5	1.6	10.9	77.4
MAPP	37.9	0.5	0.3	2.1	37.3
NPCC	209.0	10.3	6.7	45.1	187.1
SERC	244.7	3.9	2.5	16.8	56.4
SPP	97.1	1.6	1.0	6.9	50.2
WSCC	205.8	6.5	4.2	28.2	91.1
Totals	1369.4	36.4	23.7	158.9	87.3

Table A-13. Projected capacity margins by NERC region

NERC region	Capacity margins (%)	
	1994	2003
ECAR	18.0	17.6
ERCOT	21.5	20.3
MAAC	20.1	20.2
MAIN	16.6	17.1
MAPP	19.0	18.7
NPCC	25.3	24.6
SERC	16.2	16.4
SPP	18.9	18.1
WSCC	24.5	24.0
Totals	19.9	19.6

Source: North American Electric Reliability Council (1994)

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