Stranded Cost Estimates for a Restructured Electric Industry in North Carolina

Final Report
Volume 2—Task 4: Analysis of Options for Resolving Stranded Cost Issues

Options and Issues

Prepared for

Legislative Study Commission on the Future of Electric Service in North Carolina
300 N. Salisbury Street
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Prepared by

Research Triangle Institute
Center for Economics Research
Research Triangle Park, NC 27709

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Acknowledgments

Dr. Eric Hirst, Oak Ridge National Laboratory and consultant on electric industry restructuring, Mr. Stanton Hadley, also at Oak Ridge National Laboratory, and Dr. Stephen A. Johnston at RTI were primary contributors to this report. Experts from North Carolina electric utilities provided data for the models used in this report, and reviewed the modeling assumptions and results. Other key contributors at RTI were Christopher P. Engel, Nick Haltom, Paul Kudla, and Allen K. Miedema.
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This report presents background information on stranded costs, nationally and in North Carolina. It discusses key items that must be considered in estimating stranded costs and key policy decisions that affect stranded costs and the way they are recovered.

This volume builds on Volume 1, an analysis of policy options for North Carolina’s municipal power agencies (MPAs), by extending the stranded cost issue to the other North Carolina utilities with major investments in generating assets. It is a precursor to Volume 3, which incorporates the methodologies discussed in this volume. The information contained in this report reflects data and developments through the summer and fall of 1998.

The stranded costs topic is one in a series of studies being conducted by Research Triangle Institute (RTI) for the Commission on the Future of Electric Service in North Carolina (the Commission) on the overall topic of restructuring North Carolina’s electric utility industry. The entire series of studies is designed to assist the Commission in decisions on whether to introduce electric retail competition into North Carolina and if so, when and how.

Several key policy issues affect our estimates of stranded costs for North Carolina utilities. It is not possible to estimate stranded costs without some assumptions about the outcome of policy deliberations on these issues. Rather than predict these policy outcomes, we make suggestions and assumptions in this volume and then present estimates of stranded costs in Volume 3. The estimates of stranded costs in Volume 3 embody these suggestions.
and assumptions. We also estimate how sensitive the stranded cost results are to changes in these assumptions about policy outcomes.

The notion of stranded costs is unique to public utilities. It is based on investments and other commitments these utilities have made pursuant to their obligation to serve their customer base. Costs associated with these commitments that may not be able to be recovered in a competitive electricity market are referred to as “stranded.” Examples of commitments that can lead to stranded costs include the following:

- past investments in generation that cannot be fully recovered in a competitive environment;
- continuing obligations associated with these generating facilities that cannot be avoided except at greater expense, for example, payments to the nuclear decommissioning trust fund and investments (such as steam generator replacements) to maintain (but not upgrade) the capacity and efficiency rating of these generating facilities (“cap adds”) during their design life;
- past contracts for the purchase of power from independent power producers (IPPs) and nonutility generators (NUGs) pursuant to the 1978 Public Utilities Regulatory Policy Act that stipulate a higher price of power than the price of power that prevails in a competitive environment;
- agreements (“regulatory assets”) made with regulators or customers to undertake public policy programs, such as energy conservation program investments that are capitalized and then depreciated over the equipment or program life; and
- agreements (also called “regulatory assets”) made with regulators or customers to protect customers from major cost disturbances, such as delaying the recovery of costs for new, expensive generating facilities and power purchases, thereby protecting customers from “rate shock.”

In short, stranded costs are simply costs that are uneconomic (i.e., noncompetitive) in a competitive environment. This is a particular issue in the electric utility industry because of the large size and long lifetime of industry commitments.

In a sense, stranded costs associated with retail customers (customers who consume power and do not resell it) are applicable more investor-owned utilities (IOUs), because IOUs are subject to a mandated obligation to serve within their retail franchise area. This requirement is part of the franchise agreement under which they operate, and the North Carolina Utilities Commission (NCUC)
oversees this aspect of their operation and regulates their rates and service practices. However, it is common to extend the term “stranded costs” to the uneconomic costs of other utilities, even though their retail rates and service practices are not regulated by a state regulatory authority. These other utilities have traditionally understood that they have a similar obligation to serve their customers and have made large, long-term commitments. This is particularly the case in North Carolina, where the two MPAs and North Carolina Electric Membership Corporation (NCEMC) have co-invested with Carolina Power & Light (CP&L) and Duke in major generating assets.

Stranded costs in North Carolina are primarily the result of investments in large, expensive generating assets that were made during the 1970s and 1980s when the forecasted growth rate in electricity usage was much larger than it is now. Electricity growth rates in the 1950s and 1960s were also large, but the fixed costs associated with the generating assets brought into service during these time periods are essentially recovered now, so they are not a major contributor to stranded costs. The other key contributors to stranded costs are the continuing commitments associated with existing generation assets, particularly nuclear generation, and with obligations undertaken to protect customers from major cost disturbances. Unrecovered costs associated with purchases of “above-market” power from IPPs and NUGs and with social and conservation programs are not major contributors to stranded costs in North Carolina.

The most direct way to estimate stranded costs is the market valuation approach. This approach relies primarily on data from utility sales of generation assets and purchased power contacts. At the time the data were collected for this study, there were few asset sales of this type in the U.S. As time passes, however, more sales have transpired and the market valuation approach has more data to rely upon.

Two categories of methodologies can be used to estimate stranded costs: “top-down” and “bottom-up” methodologies. The “top-down” category includes straightforward methods with simple data requirements that reflect the traditional cost recovery process under regulation. This process allows utilities to recover their recurring expenses and depreciable fixed costs through rates charged to
customers. The “bottom-up” category includes methodologies that are also used in regulatory proceedings, but they are more detailed and complex and have more extensive data receipts. This category includes models that combine production cost simulations with financial analyses. Research Triangle Institute (RTI) applied both types of methodologies in this study. An overview of the two Excel spreadsheet models we used is presented in Volume 3.

Because several key assumptions and policy choices affect stranded costs, we discuss each of them in this volume. They are as follows:

- start date of retail competition;
- whether nexus is established for tax purposes;
- the price of retail power in a competitive environment;
- the discount rate used to convert a utility’s stream of annual stranded costs into a lump sum value (net present value) at the start date of retail competition;
- the length of the analysis period, which we believe should extend through the design life of existing generating assets, but which policymakers may choose to restrict to shorter time horizons. For example, policymakers may choose to end the analysis period once annual “negative” stranded costs begin to appear (i.e., whenever the projected regulated price of power falls below the projected competitive price power); and
- whether “cap adds” are included in stranded costs.

We also discuss several key policy issues related to the recovery of stranded costs. These include the following:

- whether all or a fraction of stranded costs should be recovered through rates as rate surcharges,
- the time period over which stranded costs should be recovered through rates,
- how stranded costs recovered through rates should be allocated to customer classes,
- how to recover these stranded costs through rates, and
- how to establish “true up” mechanisms to reconcile projected with actual stranded costs.

These choices can have incentive and disincentive effects, and they can affect economic efficiency and stranded cost recovery itself. We discuss these effects in this report.

This report contains several bibliographic references to other reports on the subject of stranded costs and their recovery. These
references are intended to provide the reader with a presentation of key issues and a gateway to the literature on this subject. It also sets the context for stranded cost estimation and recovery, providing the reader with a discussion of a wide range of stranded cost issues before we present our estimates of these costs in Volume 3.
1 Introduction

This topical report (Volume 2) on stranded costs for North Carolina electric utilities is one in a series of reports for the Legislative Study Commission on the Future of Electric Service in North Carolina. The Study Commission is investigating the subject of restructuring the electric industry in North Carolina and is considering whether, when, and how to introduce retail competition into the North Carolina electricity sector. The issue of stranded costs is a key topic in this investigation.

This volume contains background information and a qualitative discussion of stranded costs that highlights key assumptions and policy issues. A companion volume, Volume 3, provides quantitative estimates of stranded costs for North Carolina utilities and an indication of their sensitivity to key assumptions and policy issues. The estimates in Volume 3 are based on data provided by the utilities in the spring of 1998.

A predecessor volume, Volume 1, is entitled Policy Options for North Carolina’s Municipal Power Agencies (RTI, 1999a). It recognizes the special stranded cost problems of the two North Carolina municipal power agencies (MPAs) and their member municipalities and discusses a range of policy options to address those problems.
1.1 OVERVIEW OF NORTH CAROLINA UTILITIES

North Carolina’s electricity industry is led by two large investor-owned utilities (IOUs)—Duke Power and Carolina Power & Light (CP&L). Virginia Power (called North Carolina Power in this state), although a major supplier in Virginia, accounts for only 3 percent of North Carolina’s retail electricity sales.

Many areas in North Carolina, however, are served by municipal utilities and rural electric cooperatives. The 72 municipal electric utilities are members of ElectriCities, and 51 of these 72 utilities are members of MPAs who supply all their power requirements. There are two MPAs:

- North Carolina Eastern Municipal Power Agency (NCEMPA), which operates in eastern North Carolina and includes 32 municipal electric utilities, and
- North Carolina Municipal Power Agency 1 (NCMPA1), which operates in North Carolina’s western Piedmont and includes 19 municipal electric utilities.

The 28 rural electric cooperatives’ service territories reside completely inside North Carolina, and 27 are members of the North Carolina Electric Membership Corporation (NCEMC). Another five cooperatives serve portions of North Carolina, but their main offices are in other states and they are not members of NCEMC.

The two MPAs and NCEMC are important not only because of the electric power and services they provide to their members, but also because they have purchased significant shares of generation capacity from Duke and CP&L. In addition, they are major purchasers of wholesale power from these two IOUs for resale to their own member cities and cooperatives.

1.2 NATIONAL WINDS OF CHANGE

The U.S. electricity industry is facing winds of change that can affect its structure, operations, and regulation. These winds are blowing from several directions, including

- legislation and regulation in some states,
future emissions control policies (e.g., implementation of the Kyoto Treaty and NO\textsubscript{x} and CO\textsubscript{2} restrictions) and their effect on existing and future generating units,

improving technologies (especially for combustion turbines and combined-cycle units),

low natural gas prices, and

claims that competitive markets for electricity can better meet customer needs than regulated markets.

The electricity industry today is dominated by IOUs that are vertically integrated,\textsuperscript{1} each of which enjoys a retail-monopoly-franchise granted by the state. As a condition for this monopoly franchise, those utilities’ rates and services are regulated by state public utility commissions (PUCs).

In states that have restructured their electricity industry, the electricity industry may include separate companies that offer only one of the following electricity services: generation, transmission, distribution system control, and retail sales. In those states that adopt retail competition, generation services may be free of much of today’s state regulation. The transition from one type of structure to another will, for some utilities, expose past costs and future cost obligations that will not be compensated in competitive markets, which the utility could reasonably have expected to recover in a regulated market. These costs are potentially “stranded” and are thus referred to as stranded costs.

1.3 THE STRANDED COST ISSUE

Stranded costs, sometimes called transition costs, are the potential monetary losses that electric utility shareholders or other parties might experience as a result of structural changes in the electricity industry. These costs are not stranded until retail competition occurs; until then, they are generally recovered in rates from retail customers. They are associated with long-lived commitments that were undertaken prior to competition and are not economic in a competitive environment. These commitments were undertaken by utilities to fulfill their obligation to serve their customer base, which is a statutory obligation for IOUs. This obligation is part of an IOU’s franchise agreement. Although no formal obligation to serve

\textsuperscript{1}Vertically integrated utilities build and operate power plants, transmission systems, distribution systems, and customer-service operations all within one company.
exists for ElectriCities and NCEMC, both have adopted this obligation. Furthermore, they have co-invested with CP&L and Duke in some long-lived generation assets through joint ownership agreements.

Stranded costs attempt to reflect the loss in asset values that may occur with restructuring. These losses can be approximated as a function of the difference between regulated retail electricity prices for generation services and the competitive market price of power. In essence, the retail monopoly franchise that IOUs enjoy today permits them, with approval from their state regulatory commission, to charge customers for the prudently incurred costs of producing electricity. These prudently incurred costs, and the resulting price of power to customers, may be above the market price in competitive electricity markets if

- new or improved generation technologies have emerged that are more efficient and cheaper, or
- regulatory authorities have required utilities to undertake obligations that would not necessarily be undertaken by suppliers in a competitive market (e.g., universal service and energy conservation programs).

In competitive electricity markets, the frequent interaction of buyers and sellers, rather than regulators, will determine prices. If prices in competitive markets are below regulated prices for current providers, then stranded costs will arise for these providers. Stranded costs associated with generation assets and long-term power purchase agreements increase as the difference between the regulated price charged by current providers and the competitive price increases.

The amounts of money at stake are potentially substantial. Estimates of stranded costs in the U.S. vary widely. For example, researchers at Moody’s Investors Service (Hackett, Cohen, and Abbott, 1996) analyzed data for 116 utilities representing more than 80 percent of the assets of all U.S. investor-owned electric utilities. Moody’s estimated that stranded costs could range from $50 billion to $300 billion, with the most likely value being $136 billion, equivalent to almost 90 percent of shareholder equity for these utilities.

Not only is a great deal of money at stake, but that money is distributed unevenly across utilities, states, and regions. Certain
low-cost regions of the country (such as the Pacific Northwest) have little exposure to stranded costs, while other regions (such as California and the Northeast) face substantial problems. These problems have several origins, but they are primarily related to investments in nuclear power and large purchases of expensive power from independent power producers (IPPs).

The costs discussed here already exist and are, in general, being paid by today’s retail electricity consumers. Increasing competition exposes these costs but generally does not create new costs. Legislators, regulators, and others deliberating a move to retail competition need to address the allocation of these costs and establish clear rules to determine how they will be measured and shared among different groups (e.g., utility shareholders, retail customers in different classes, wholesale suppliers, and taxpayers). Government failure to render clear policy decisions on the allocation of these costs will likely cause serious problems, including extensive litigation and delays in the implementation of competitive markets.

1.4 MAJOR COMPONENTS OF STRANDED COSTS

Stranded costs are basically booked costs and costs associated with future obligations that cannot be recovered in a competitive market. Stranded costs can include contributions from four components:

- **Assets**, primarily expensive power plants with several years of service life remaining. For example, some utilities own nuclear plants that were judged to be economic when they were built. These plants cost much more to build than today’s power plants. Although these nuclear plants were built with the approval of regulators (in the case of IOUs) and financial authorities, the price received in a competitive electricity market for the electrical output from these expensive plants may not be enough to repay the remaining (undepreciated) capital costs of the plants.

- **Liabilities**, primarily in power purchase contracts and fuel-supply contracts. For example, until a few years ago, a New York state law required utilities to purchase the output of certain types of power plants for at least 6¢/kWh. At the time, 6¢/kWh may have seemed reasonable, but it is much higher than today’s wholesale price of power. However, utilities signed long-term contracts at these high prices and, generally speaking, they must honor their contractual obligations.
“Regulatory” assets, whose value is based on regulatory
decisions rather than on market forces. They include
defered expenses and taxes that regulators allow utilities to
place on their balance sheets. For example, a regulatory
commission might agree to defer some of the costs of an
expensive new power plant to avoid “rate shock.” The
commission might allow the utility to add these costs to
rates gradually over several years. In essence, this
agreement is a promise from the state regulator to the utility
that ultimately, although not today, it will recover all its
costs. If the utility’s customers can choose alternate
suppliers, however, the regulator may have difficulty
keeping this promise to the utility. Similarly, deferred
expenses such as contributions to the nuclear
decommissioning trust fund and deferred tax liabilities may
also be difficult to recover in a competitive environment.

Public policy programs, including tax collection,
environmental compliance beyond that required by law,
demand-side management programs, special programs for
low-income customers, and support for energy research and
development. These costs are stranded if they have been
capitalized and if the undepreciated portion is
unrecoverable once retail competition begins.

In North Carolina, stranded costs are associated primarily with a
few nuclear stations built by Duke and CP&L during the 1970s and
1980s, with ownership participation by the two MPAs and NCEMC.
A brief history of this experience is presented in the next section.
Stranded costs for North Carolina utilities have their origins in the market environment of the 1960s through 1980s. This market environment influenced decisions made by electric utilities and regulators during this time period. Many of these decisions involved long-term commitments that were made at a time when restructuring of the electric utility industry was not even being discussed. Introduction of retail competition prior to the expiration of these commitments leads to the issue of stranded (unrecovered) costs.

2.1 1960s

Rapid electricity load (kW) and consumption (kWh) growth characterized the decade of the 1960s in North Carolina and surrounding states. This growth reflected a growth in population, as well as increased industrialization and electrification (especially air conditioning). Peak load and energy consumption growth forecasts of 7 to 9 percent per year were not uncommon. Generation planning reserve margins (i.e., generating capacity above peak load) to maintain reliability were typically around 20 percent.

To meet these projected requirements, utilities began to plan for major additions to generation capacity. The emphasis was on large, baseload generating units. Baseload units are designed to operate continuously throughout most of the year, and several units are frequently co-sited at a single plant site.
These baseload units offered the promise of meeting the projected requirements with the least number of units. They also offered the promise of meeting these requirements with lower costs per kWh as a result of economies of scale.1 The primary fuel types under consideration for these units included coal, oil, and a newer fuel source, nuclear.

The forecasts and capacity expansion plans that were developed during this period were critically dependent on several key assumptions about customer, technology, and regulatory behaviors. Changes in any of these assumptions can have major impacts on large baseload facilities, because they are more expensive and take a longer time to build than other types of units (e.g., smaller units designed to follow load fluctuations or to serve load peaks).

Although large baseload units are more expensive to build, lower operating costs over their lifetime can lead to lower total costs over the expected operating lifetime of the units (life-cycle costs). But their higher construction costs and their long construction times mean they are especially vulnerable to increases in financing costs and to midstream regulatory changes.

Some of the key assumptions at this time were as follows:

- Economies of scale would help lower rates and stimulate electricity use.
- The financing requirements for this new capacity would be absorbed by financial markets without sharp increases in the cost of financing.
- The larger and more complex generation technologies would pose no major construction and operation problems, so that the anticipated economies of scale would be realized once units were placed into service.
- There would be no major changes in regulatory requirements associated with generation unit siting and licensing.

Large coal, oil, and nuclear units were being planned and constructed during this period. The earliest nuclear units built by North Carolina utilities were built in surrounding states—Oconee (Duke) and Robinson (Carolina Power & Light [CP&L]) in South Carolina and Surry (North Carolina Power as Virginia Electric Power Company [VEPCO] in Virginia). The Oconee plant includes

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1Economies of scale here refers to costs per unit of output (i.e., scale of operation) that fall as generating unit size increases.
three nuclear units, the Surry plant two, and the Robinson plant one. These plants received approvals (in the form of Certificates of Public Convenience and Necessity) from the South Carolina Utilities Commission and the Virginia State Corporation Commission to proceed with siting and construction in these states during the 1960s. Nuclear units at all three plants came into service during the 1971 to 1973 time period. Favorable financial, construction, and operating experience with these units helped to encourage plans for additional nuclear units in North Carolina utility expansion plans.

2.2 1970 TO MID-1980s

The 1970s brought new events and changes in the market and regulatory environments that affected utility expansion efforts. Key events during this period include the

- Arab oil embargo (1973) and

The first event eventually resulted in an approximate quadrupling of oil prices, with similar increases in natural gas prices. Energy planners at various levels of government and among utilities recognized the geopolitical uncertainties associated with oil supplies and prices. Some forecasts of oil prices were $100 per barrel, which is approximately six to seven times what it is today. The federal government began a large effort in 1974 to plan for “energy independence,” and utilities began to remove oil-fired generation from their plans. During the latter half of the decade, natural gas shortages began to appear in winter months, and federal rules required curtailment of large users (including utilities) first. Further, in 1978 Congress passed the Fuel Use Act that outlawed the use of natural gas as a fuel in utility baseload generation. This restriction was repealed in 1987.

During this time frame, utilities relied almost exclusively on new coal and nuclear plants to meet growth in baseload requirements. Because coal prices were more sensitive than nuclear fuel to increases in oil prices, nuclear was increasingly viewed as the preferred baseload alternative by many utilities. North Carolina utilities were no exception.
The second event, the Three Mile Island incident, resulted in major
design changes mandated by the Nuclear Regulatory Commission
(NRC) to increase nuclear power plant safety. These changes
resulted in major increases in nuclear capacity costs because larger
design and construction expenditures were now required per unit of
capacity. Construction delays and unusually high inflation rates
resulted in even higher costs. These changes affected nuclear
capacity under construction as well as newly planned nuclear
capacity, and the total cost (planning, design, construction, and
financing) of nuclear capacity typically increased by a factor of
three to five times the original estimate.

North Carolina utilities had several nuclear projects in the planning
and construction stages at this time, and they were affected by the
NRC design changes. Those that were further along in construction
were typically affected less than those that were in the initial stages.
Table 2-1 provides examples of CP&L and Duke nuclear projects
underway during this time period.

During this time, utilities were also planning and constructing coal-
fired generation projects. Duke’s Belews Creek plant (2,160 MW)
includes two units that entered service in 1974. CP&L’s Roxboro
Unit #4 (738 MW) was certified by the North Carolina Utilities
Commission (NCUC) in 1972 and entered service in 1980. North
Carolina Eastern Municipal Power Agency (NCEMPA) owns
13 percent of this Roxboro Unit #4. Mayo (736 MW) was certified
as a two-unit plant by the NCUC in 1977; Unit #1 entered service
in 1983, but CP&L cancelled Unit #2 in 1987. NCEMPA owns
16 percent of this Mayo unit.

VEPCO’s North Anna plant (1,958 MW), which includes two
nuclear units, entered service in Virginia in 1978. Its Bath County
pumped storage plant (a hydro facility that uses cheap off-peak
power from nuclear units to provide additional on-peak power)
entered service in 1985. VEPCO had also planned a coal-fired
plant in Bertie County, North Carolina, but it was cancelled prior to
certification.

These rapid building programs and emerging cost increases in the
aftermath of the Arab oil embargo led to downward pressure on
bond ratings and stock values below book as early as 1984. They
also led to frequent rate hearings during this time period and some
Table 2-1. Examples of Nuclear Projects Underway Between 1970 and the Mid-1980s

<table>
<thead>
<tr>
<th>Nuclear Plant Name</th>
<th>Operator</th>
<th>Number of Units Certified</th>
<th>NCEMC or MPA Ownership</th>
<th>NCEMC or MPA Ownership Share</th>
<th>Planned Capacity (MW)</th>
<th>Actual Capacity (MW)</th>
<th>In-Service Date</th>
<th>Cancellation Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Catawba 1</td>
<td>Duke</td>
<td>1</td>
<td>NCEMC</td>
<td>56.25%</td>
<td>1,200</td>
<td>1,205</td>
<td>1985 (unit 1)</td>
<td>N/A</td>
</tr>
<tr>
<td>Catawba 2</td>
<td>Duke</td>
<td>1</td>
<td>NCMPA1</td>
<td>75%</td>
<td>1,200</td>
<td>1,205</td>
<td>1986 (unit 2)</td>
<td>N/A</td>
</tr>
<tr>
<td>Cherokee&lt;sup&gt;a&lt;/sup&gt;</td>
<td>Duke</td>
<td>3</td>
<td>N/A</td>
<td>N/A</td>
<td>3,840</td>
<td>0</td>
<td>N/A</td>
<td>1982 (units 2,3); 1983 (unit 1)</td>
</tr>
<tr>
<td>McGuire 1</td>
<td>Duke</td>
<td>2</td>
<td>N/A</td>
<td>N/A</td>
<td>1,150</td>
<td>1,220</td>
<td>1981 (unit 1)</td>
<td>N/A</td>
</tr>
<tr>
<td>McGuire 2</td>
<td>Duke</td>
<td>2</td>
<td>N/A</td>
<td>N/A</td>
<td>1,150</td>
<td>1,220</td>
<td>1984 (unit 2)</td>
<td>N/A</td>
</tr>
<tr>
<td>Perkins&lt;sup&gt;a&lt;/sup&gt;</td>
<td>Duke</td>
<td>3</td>
<td>N/A</td>
<td>N/A</td>
<td>3,840</td>
<td>0</td>
<td>N/A</td>
<td>1982 (units 1,2,3)</td>
</tr>
<tr>
<td>Brunswick 1</td>
<td>CP&amp;L</td>
<td>1</td>
<td>NCEMPA</td>
<td>18%</td>
<td>800</td>
<td>866</td>
<td>1975 (unit 1)</td>
<td>N/A</td>
</tr>
<tr>
<td>Brunswick 2</td>
<td>CP&amp;L</td>
<td>1</td>
<td>NCEMPA</td>
<td>18%</td>
<td>800</td>
<td>866</td>
<td>1977 (unit 2)</td>
<td>N/A</td>
</tr>
<tr>
<td>Shearon Harris 1</td>
<td>CP&amp;L</td>
<td>4</td>
<td>NCEMPA</td>
<td>16%</td>
<td>900</td>
<td>951</td>
<td>1987 (unit 1)</td>
<td></td>
</tr>
<tr>
<td>Shearon Harris&lt;sup&gt;a&lt;/sup&gt; (Other Units)</td>
<td>CP&amp;L</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>2,400</td>
<td>0</td>
<td>N/A</td>
<td>1981 (units 3,4); 1983 (unit 2)</td>
</tr>
</tbody>
</table>

<sup>a</sup>Generating unit detail is not provided in this table unless those units were completed and entered service.
key actions by the NCUC during the most financially stressful part of this era. One example of these actions was the allowance of construction work in progress in the rate base. This action provided ratepayer help in financing generation facilities before they entered service rather than wait until these units were completed and became “used and useful” in service, which was the regulatory treatment prior to the action. Another example was the requirement that Duke set up a levelization account to spread cost recovery through rates for the power from the Catawba plant Duke was “buying back” from North Carolina Electric Membership Cooperative (NCEMC) and North Carolina Municipal Power Agency 1 (NCMPA1). The NCUC ordered Duke to amortize the cost of this “buyback” over a 10- to 15-year period to avoid “rate shock” on its retail customers. This buyback agreement was negotiated because NCEMC and NCMPA1 could not use all their ownership share in Catawba until the end of this period.

Another significant change that occurred during this period was the rate of load growth being forecast by utilities. All utilities significantly lowered their forecasts in response to slowdowns in actual load growth. Load growth slowed in response to

- higher electricity prices,
- lower growth in kWh usage per customer, and
- a slowdown in the rate of economic growth.

To illustrate how much load growth forecasts were reduced, Duke’s forecast for a 10-year horizon dropped from a forecast of 8 percent per year made in 1975 to a forecast of 2 percent per year made in 1985. CP&L’s forecasts for a similar horizon dropped from 7.7 percent per year to 2.5 percent per year during this same period. The lower forecasts led to lower requirements for future new capacity to serve load growth.

### 2.3 LATE 1980s TO PRESENT

Since the late 1980s, North Carolina utilities have added very little new capacity. New additions (e.g., Duke’s Bad Creek pumped storage plant and its Lincoln County combustion turbine plant, and VEPCO’s Darbytown combustion turbine plant) are peaking units, not baseload units. The combustion turbine units, which have been added primarily for reliability purposes, are fueled by gas or oil, not
coal or nuclear. CP&L has not added new capacity during this period, and neither the municipal power agencies (MPAs) nor NCEMC has purchased additional shares of generating assets during this period.

2.4 SUMMARY

The potential stranded costs for North Carolina utilities are primarily related to baseload nuclear generation investment decisions and approvals that were made in the late 1960s and early 1970s for new plants and new units at existing plants that entered service in the 1980s. In particular, the most recent nuclear plants in this class—Catawba and Harris, in which NCEMC, NCMPA1, and NCEMPA own significant shares—are also the most expensive of these plants.

Some regulatory assets are related to these plants. For example, to avoid rate shock when expensive new generating units entered service in the 1980s, the NCUC often required that the rate base associated with these units be phased in over time. In addition, NRC-mandated payments to the nuclear decommissioning trust fund over the life of nuclear units are another potential stranded cost. “Above-market” power purchase contracts, which are a significant source of stranded costs in some other states, are not a significant issue in North Carolina. They are an issue in some states (e.g., Virginia and New York), because regulatory authorities directed investor-owned utilities (IOUs) (typically during the 1980s and occasionally even into the early 1990s) to purchase power from nonutility generators at prices that subsequently turned out to be far above market prices. Fortunately, the NCUC did not follow the actions of these states.
3 Stranded Cost Estimation

3.1 INTRODUCTION
Utilities and regulators can use a variety of approaches to calculate stranded costs. These approaches can be categorized as market or administrative approaches. Administrative approaches can be further categorized as “top-down” or “bottom-up” approaches. We summarize each of these approaches in this section.

3.2 MARKET VALUATION VS. ADMINISTRATIVE DETERMINATION
Market valuation relies on recent sales of generation and related assets and long-term liabilities to determine their market values. Market values typically differ from book values, because book values reflect the application of a prescribed depreciation schedule to the original cost of the asset. Because asset values in any year can appreciate or depreciate depending on market conditions, book values can be an inaccurate indicator of market values. The amount by which the market value of a utility’s generation assets falls below book values is typically a major component of stranded costs. As of mid-1998, however, data on asset sales were limited, so the market valuation approach was not used in this study.

Administrative determination uses forecasting, modeling, or other analytical techniques to estimate stranded costs. This approach relies on modeler assumptions about future market environments. It is not as accurate as market valuation, but it may be the only alternative if recent and comparable sales data are not available for
the assets in question. Administrative approaches are used more often than market valuation approaches because of the dearth of recent asset sales data. “True-up” methods are used during the first years of competition to adjust for differences between predicted (from an administrative approach) and actual stranded costs.

### 3.2.1 Market Valuation

As of May 1998, several utilities had conducted auctions resulting in the sale of non-nuclear generating units at prices well above their book values (see Table 3-1). As of this date, no nuclear units had been auctioned or otherwise sold by a utility. According to the Edison Electric Institute, 27 utilities had sold or announced the sale of more than 53,000 MW of capacity. The sale prices suggest that new buyers value these units more highly than the accounting numbers imply (i.e., the market prices were above book values).

<table>
<thead>
<tr>
<th>Selling Utility</th>
<th>Capacity Sold (MW)</th>
<th>Ratio of Sale Price to Book Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boston Edison</td>
<td>1,983</td>
<td>1.2</td>
</tr>
<tr>
<td>Central Maine Power</td>
<td>1,185</td>
<td>3.5</td>
</tr>
<tr>
<td>Commonwealth Edison</td>
<td>1,598</td>
<td>1.0</td>
</tr>
<tr>
<td>Commonwealth Energy</td>
<td>984</td>
<td>5.8</td>
</tr>
<tr>
<td>EUA</td>
<td>244</td>
<td>1.9</td>
</tr>
<tr>
<td>New England Electric</td>
<td>3,960</td>
<td>1.5</td>
</tr>
<tr>
<td>Pacific Gas &amp; Electric</td>
<td>2,745</td>
<td>1.3</td>
</tr>
<tr>
<td>Southern California Edison</td>
<td>9,562</td>
<td>1.9</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>22,261</strong></td>
<td><strong>Weighted Average = 1.7</strong></td>
</tr>
</tbody>
</table>


The premium of market values above book values is larger in areas that are “capacity short” now or in the near future. North Carolina is not in that situation currently. Recent (September 1998) interpreted resource plan filings by North Carolina utilities indicate plans for significant additions to capacity in the over the 10-year
planning horizon required in the filing. In “capacity short” areas, divestiture of generation (generation asset sales) may be a significant way to reduce stranded costs. Indeed, several states (e.g., California and Massachusetts) conditioned stranded cost recovery on the utilities’ willingness to sell substantial portions of their generating assets. Divestiture of generation assets is a strong tonic and has thus far been restricted to high-rate states and utilities with large stranded costs.

Market valuation offers several benefits relative to administrative determinations of stranded cost amounts. First, the use of markets to determine the values of what might be stranded assets and liabilities provides an unambiguous determination of their value. This market determination means that the state regulatory commission need not conduct the equivalent of lengthy and contentious rate cases in the form of stranded cost determinations.

Second, the price obtained in an auction or through careful negotiation will reflect the highest value of the assets. Thus, the prices at which these assets and long-term contracts are sold reflect the highest bids offered. Third, the sale of generating units and long-term power purchase contracts can reduce market concentration, which in turn reduces potential market power abuses. Finally, once the assets and liabilities are sold, the amount of stranded costs remaining may be smaller (and perhaps zero or negative); thus, the transition period can be shorter than when an administrative determination approach is used. For example, the sale of the fossil and hydro generating units owned by the New England Electric System cut its stranded costs in half.

On the other hand, a poorly designed and badly timed auction could produce bids well below the true market values for the assets and contracts being sold. In such a case, utility customers would be asked to pay stranded costs much higher than they need to. Some analysts worry that the simultaneous sale of too many megawatts of generating capacity could lead to a “fire sale” with very low prices. The sale of generating units before the structure and operation of competitive generation markets are established could yield sale prices that do not reflect their long-term market value. However, the experience to date suggests that these concerns may not be a large problem.
An alternative to an auction is a negotiated sale. A negotiated sale can avoid the “fire sale” problem, and it can be superior to an auction when the ownership situation is complex and there are multiple objectives and constraints involved in an asset sale. This topic is discussed in our report, Policy Options for North Carolina’s Municipal Power Agencies, Volume 1 of our stranded cost report series.

The auction format can be important. To date utilities have used an auction format that calls for only one round of sealed bids. The approach used by the U.S. Federal Communications Commission to auction parts of the electromagnetic spectrum used multiple rounds of bidding. Multiple rounds might yield higher prices because bidders can adjust their offers from round to round to assemble the portfolios of resources in which they are most interested.

As another alternative to asset sales, utilities could spin off generating assets to a separate division of the company or to a new company. The value of that company, as reflected by its stock price, could be used to determine the market value of the generating assets. Determining the appropriate time(s) to observe the stock price may be difficult and contentious, however. The stock price of a spin-off will reflect not only investors’ perceptions of asset value but also the value of the new company’s management and staff, among other characteristics. Once customers, through a stranded-cost charge, have paid shareholders for the remaining book value of these assets, shareholders have no further claim on customers for these assets.

When considering the specific market valuation approach to use, the potential tax implications should be assessed. A sale of assets, such as the divestiture of utility generating plants for cash, will be treated as a taxable event for federal and state income tax purposes. A spin-off transaction will not be considered a taxable event if the transaction conforms to tax laws dealing with spin-offs. The potential tax consequences of different market valuation approaches suggest a need to elicit opinions of tax counsel prior to implementing a specific process. Asset sales may also raise complications with mortgage bonds, many of which are backed by specific assets.
Because different market valuation approaches have different tax effects, decisionmakers should look beyond market value in deciding between auctions and spin-offs. An asset would have to sell well above the value of a spin-off to yield the same after-tax proceeds. In addition, the transaction costs associated with these different approaches must be considered, particularly if ratepayers are funding some portion of these activities. Further, unless the sale or spin-off is straightforward (e.g., an asset sold at auction with many bidders), determining the market value or the net proceeds from the transaction may be complicated. For example, a sale or spin-off may include the purchase of operations and maintenance (O&M) contracts, plant output, or supplemental services. Regulators must then separate the payment for the asset itself from these other purchases.

3.2.2 Administrative Determination

Administrative determination of stranded costs uses analytical techniques similar to those used in traditional rate cases to estimate the market value of utility assets and obligations. The methods used to implement this approach can be classified as top-down or bottom-up.

Top-down methods are less data-intensive than bottom-up methods, and the results are less detailed. Bottom-up methods involve a more detailed modeling process, typically at the individual generating unit level or by type of generating unit.

Top-Down Method

Top-down approaches treat the utility as the unit of observation, whereas bottom-up approaches use individual assets or liabilities as the unit of observation. In top-down approaches, the utility's average embedded cost of electricity production is compared with an average 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 stranded cost situation. The Revenues Lost approach, developed by the Federal Energy Regulatory Commission (FERC) in its Order 888 to remove stranded costs in wholesale markets is a top-down
method. We modified and enhanced this top-down method to estimate stranded costs in retail markets.

Regulators might prefer top-down methods because of their administrative simplicity and reliance on readily available data and computer models. Such methods are well suited for developing initial estimates of the magnitude of the stranded cost problem for a particular utility or state. However, in regulatory determinations of the actual dollar amounts to be recovered, public utility commissions (PUCs) might prefer the greater detail of bottom-up methods. This detail is especially important if commissions decide to authorize recovery of utility-shareholder investment in certain assets but not necessarily recovery on these investments (i.e., return on equity), or if regulators want to allow utilities to recover different fractions of stranded costs for different types of assets and liabilities.

**Bottom-Up Method**

Bottom-up methods compare the fixed costs of individual assets and obligations with the operating income (revenues minus operating expenses) produced from their electricity sales. Stranded costs arise when a plant’s operating income does not cover its fixed costs. In contrast, a plant with operating income in excess of its fixed costs can help offset the unrecovered fixed costs of another plant. Some early estimates of stranded costs were too high because they analyzed only those generating units with book values above market values, leading to an estimate of gross costs. An accurate assessment of such costs must include all assets, those with book values below as well as above market values, to derive an estimate of net stranded costs.

A bottom-up approach requires calculating 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 simulations for both the utility in question and the surrounding utilities and independent power producers. Such calculations require a large set of assumptions concerning customer loads, transmission-system characteristics, and the operation and costs of individual generating units.
Summary

Regardless of the method used to estimate the amount of stranded costs, one must make certain assumptions. Although many factors affect the calculation of stranded costs, only a few factors make a big difference. The most important factors affecting stranded cost magnitudes include the future market price of electricity, the timing and extent of retail competition, amount of utility regulatory assets, and utility fixed production costs. Factors likely to have little effect on estimates of stranded cost amounts include public policy program costs, inflation rate, customer load factors, and transmission and distribution system loss factors.

Of the critical factors that affect stranded costs, some can be influenced by the utility, some by the PUC or legislature. Others are essentially beyond the control of either party. As examples, the PUC can affect the start date and extent of competition and utilities can seek to cut their production costs. But wholesale prices—probably the most important factor—are largely independent of utility or PUC actions.

Because so many assumptions are required to develop estimates of the dollar amounts at stake, PUCs may want to apply periodic adjustments to their initial estimates. Such true-ups (discussed in Section 4.2) would reduce the risk that any group would pay too much or enjoy windfall profits. On the other hand, the regulatory proceedings associated with such true-ups could be complicated, time consuming, and litigious. And, unless properly designed, such mechanisms could reduce a utility’s incentive to perform efficiently.

3.3 KEY ISSUES

The approach used to estimate electric utility stranded costs in this study is the administrative determination approach. We used both a top-down and a bottom-up method. Several key issues affect the estimates based on these methods, as discussed below.

3.3.1 The Assets and Obligations to Include in the Analysis

In Section 1, we described the four categories that potentially contribute to electric utility stranded costs:
generating assets, including long-lived commitments tied to those assets (e.g., contributions to the nuclear decommissioning trust fund);

- long-term power purchase contracts;

- regulatory “assets,” (commitments made in response to regulatory directives, such as delayed cost recovery for large, costly generating facilities when they enter service, so as to avoid “rate shock”); and

- utility-based public policy programs, which are sometimes categorized as regulatory assets.

By definition, only assets and obligations incurred prior to the start of retail competition should be included in the estimation of stranded costs. In addition, all generating assets and obligations and all power purchase contracts should be included. However, these topics can be contentious. Examples of issues that have been raised in these determinations are as follows:

- Should generation assets whose current book value is likely to be below market value be included in the analysis, or should the analysis be restricted to generation assets whose market value is below book value? In our reference case we included all generating assets.

- Should future investments made to maintain the capacity and efficiency rating of existing generating units through their design life (“cap adds” in investor-owned utility [IOU] terminology) be included in the analysis? Cap adds do not include investments made to repower generating units, nor do they include investments to extend the life of generating units beyond their design life. An example of a cap add is the replacement of a steam generator when it fails and when it is clear that this “system component replacement” will be cheaper per kW than the cost of new generating capacity. In our reference case we included cap adds.

- Should all long-term power purchase contracts be included in the analysis, or should the analysis be restricted to contracts that are likely to be above current wholesale market prices? In our reference case, we included all long-term power purchase contracts.

- What long-term utility obligations in the regulatory assets category are directly related to their obligation to serve under regulation (i.e., were undertaken pursuant to the regulatory compact between IOUs and state regulators), or reflect a response to regulatory directives (e.g., from the Internal Revenue Service [IRS] and Nuclear Regulatory Commission [NRC] as well as state regulators)? In our reference case we included all regulatory assets submitted by the IOUs as long as they were incurred as a result of past
regulatory directives or were directly related to their obligation to serve.

Should contributions to the nuclear decommissioning trust fund be included? These contributions are a legacy of past investments in nuclear capacity that were approved by state regulators. The current annual contribution rate may understate the future contribution rate if nuclear decommissioning becomes a more contentious issue. In our reference case we included the current annual contribution rate.

The issue of what items to include in each category is essentially a policy issue. It will ultimately be determined in regulatory proceedings, or perhaps in subsequent litigation if utilities interpret the disallowance of some of these items as a “public takings” issue.

### 3.3.2 Start Date of Retail Competition

Stranded costs have a time dimension. A utility will actually have annual amounts of stranded cost exposure (sometimes referred to as “strandable” costs) into the foreseeable future. These annual amounts tend to decline over time, particularly for IOUs.

Strandable costs become stranded costs only after the onset of retail competition. Thus, delays in the onset of retail competition can reduce stranded costs by providing time for the larger annual amounts that exist in the immediate future to be recovered through traditional retail rate regulation. Delays can also provide time for utilities to mitigate some of these costs (e.g., via asset writedowns or accelerated depreciation). Even if utility mitigation does not occur, stranded costs will be lower because the annual amounts will be smaller, and the time horizon over which they occur will be shorter. The effect on stranded costs of a later start date of retail competition is illustrated in Figure 3-1. In this figure, annual stranded costs throughout the time period from E to T (i.e., annual stranded costs within Areas A and B) are associated with the earlier start date E. However, only the annual stranded costs from time period L to T (i.e., annual stranded costs within Area B only) are associated with the later start date L. The net present value (NPV) of the annual cost stream within Areas A and B at time E is larger than the NPV of the annual cost stream within Area B at time L.

The start date of retail competition is a major policy issue. In our analysis, we considered four start dates of retail competition: January 1 of Years 2000, 2002, 2004, and 2006. We assumed
Figure 3-1. Effect on Stranded Costs of Late Start Date of Retail Competition

<table>
<thead>
<tr>
<th>Legend</th>
</tr>
</thead>
<tbody>
<tr>
<td>E      = Early Start Date of Retail Competition</td>
</tr>
<tr>
<td>L      = Later Start Date of Retail Competition</td>
</tr>
<tr>
<td>T      = Termination of Analysis Period</td>
</tr>
<tr>
<td>A + B  = Annual Stranded Costs Associated with E</td>
</tr>
<tr>
<td>B      = Annual Stranded Costs Associated with L</td>
</tr>
</tbody>
</table>

2004 for our reference case. We assumed full retail competition would begin on these dates. We did not include a phase-in period (e.g., a period during which some customers would become eligible one year and other customers the next).

Our results, reported in Volume 3, show how stranded costs decline with later start dates of retail competition. The decline is much faster for the IOUs and North Carolina Electric Membership Cooperative (NCEMC) than for the two municipal power agencies (MPAs). Volume 1 discusses a broad array of policy options to address the MPAs’ sizeable and persistent stranded cost problems.

### 3.3.3 Benchmark Market-Clearing Price of Power

Administrative determination of stranded costs, whether by a bottom-up or a top-down method, requires a benchmark market-clearing price of power. Both methods basically compare a time
trajectory of regulated prices against a time trajectory of market prices to determine stranded costs related to generation assets and power purchase contracts.

The market price of power is an issue because current power prices are regulated, and it is difficult to extrapolate prices from a regulated environment to a deregulated one. This applies even if we assume that only generation will be deregulated (i.e., transmission and distribution services will continue to be regulated), as we have done in our analysis.

In our analysis we examined three (low, intermediate, and high) benchmark market-clearing price of power series, which we refer to as market-clearing price scenarios. The low scenario is an average of forecasts made by the IOUs; the U.S. Department of Energy (USDOE); and Resource Data International (RDI), a national consulting firm to the electric industry and regulatory bodies. These forecasts were averaged because they were very similar.

The high scenario reflects the expected cost of new capacity under the assumption that new capacity will be in the form of gas-fired combined-cycle units. This type of unit is flexible and can serve continuous, cyclical, and peak demands of customers. As customer demand grows and existing reserve capacity becomes scarce, new generation capacity will need to be expanded to replenish reserves and serve this demand growth. In this situation, electricity prices in a competitive market will rise to the point where it becomes economical to bring new capacity into service. Recent sales of power plants (see Table 3-1) suggest that the market value of power from these units reflects the cost of replacement power (i.e., power from new capacity) in geographic areas that are “capacity short.” In other words, a market price series based on replacement cost is consistent with current market evidence in areas that are “capacity short.” Currently, North Carolina is not in this situation, but that could change in the future as demand continues to grow relative to the supply capability of existing generation resources as noted in Section 3.2.1.

The intermediate scenario is simply a weighted average of all our price scenarios. We weighted the low and high scenarios by the number of forecasts used to create them. Because three forecasts were included in the low scenario and a single forecast in the high
scenario, the intermediate scenario is closer to the low scenario. We used the intermediate market-clearing price of power series in our reference case.

The benchmark market-clearing price of power series to be used for stranded cost determination is essentially a policy issue. Regulators will have to specify a benchmark market-clearing price of power series in advance, and they will likely have to specify definitive guidelines and assumptions for utilities to use in developing the stranded cost estimates based on these price series. Otherwise, stranded costs filed by utilities will vary tremendously as a result of different assumptions about the time trajectory of this very important benchmark variable. As indicated in Volume 3, very small percentage changes can dramatically change, or even eliminate, the projected stranded cost burden.

### 3.3.4 Discount Rates

Discount rates are used to compare the value of money in a current time period with its value in some future period. In essence, those rates reflect the time value of money. For example, $1.00 today that can earn an annual rate of interest of 5 percent will be worth $1.05 a year from now. Conversely, $1.05 a year from now is worth $1.00 today (the “present value”) when “discounted” by 5 percent (the “discount rate”).

Discount rates are used in stranded cost studies to convert the stream of stranded costs after retail competition begins to a present value. The present value year can be arbitrary—for example, it can be 1998, or it can be the year in which retail competition is assumed to begin. In our analysis we discounted to the various years when we assumed retail competition might begin (2000, 2002, 2004, 2006).

The choice of a discount rate is an important issue, because it can significantly affect the present value of the stream of annual stranded costs. Larger discount rates reduce the present value of stranded costs. Stranded costs that are further out in time are more sensitive to the choice of discount rate, because the annual amounts are discounted over more years to convert them into present value amounts.
There are several candidates for a discount rate to use in the estimation of the present value of stranded costs. The choice should reflect the appropriate opportunity cost of money to the party (e.g., investors or creditors) that is at risk if stranded costs are not recovered through rates. In our reference case we used the cost of equity (the annual percentage rate that IOUs estimate they have to pay stockholders to obtain equity financing) as the discount rate for IOUs. We used the cost of equity as the discount rate for IOUs because stranded costs for IOUs relative to their total asset values and revenues are large enough to jeopardize returns to investors, but are not large enough to jeopardize debt repayment to creditors. We used the cost of credit for other utilities—the cost of borrowing for NCEMC, and the cost of tax-exempt debt financing for the MPAs—because these utilities do not have stockholders, and creditors are their sole source of external financing.

Using cost of equity to discount stranded costs for IOUs has a precedent among economists in stranded cost proceedings. Dr. John Landon of the National Economic Research Associates, Inc. (NERA), in testimony before the Pennsylvania PUC in 1995, advocated its use in the Philadelphia Electric Company competition proceeding. In contrast, IOUs prefer to use their weighted-average cost of capital, which includes their cost of debt as well as their cost of equity (the weights are the proportions of each in their capital structure) as the discount rate. This preference is based on the proposition that because the weighted-average cost of capital was used in ratemaking under regulation, it should also be used in stranded cost determination. Its use will also increase the present value stranded cost estimate associated with any annual stranded cost stream.

The choice of discount rate is a policy issue that will have to be resolved in regulatory proceedings on stranded costs.

3.3.5 Whether to Include ‘Negative’ Stranded Costs

“Negative” stranded costs can arise in administrative determinations of stranded costs when the cost of power from existing generating units and purchased power contracts falls below the benchmark market price. This situation is more likely when all generating units are included in the analysis, and when the future time period included in the analysis is long. Inclusion of all
generation units means that some units that can supply power at low total (operating and depreciated capital) cost will be included. Long future time periods increase the chance that the benchmark market price of power will overtake the regulated price of power from existing generating units sometime in the future.

Inclusion of negative stranded costs will reduce total stranded costs. In our reference case, we included all generating units and purchased power contracts. We also extended the time frame of analysis to 2020, which is still less than the expected lifetime of some existing generating units. Annual stranded costs were negative for several utilities during the 2010 through 2020 time period, and we included these negative stranded costs in our analysis.

This issue has been debated vigorously. IOUs recommend excluding negative stranded costs, especially by ending the analysis period at the “crossover” year (i.e., the year when the benchmark market price of power overtakes the regulated price of power). At that point, they claim they are competing on the same playing field as their competitors. They also make the point that uncertainty grows with time, so distant projections are less reliable than near-term ones. Advocates for including negative stranded costs claim that their inclusion is required for fairness and consistency. Their notion is that ratepayer liability for stranded costs should also imply ratepayer assets in the form of negative stranded costs.

### 3.3.6 Nexus for Tax Purposes

Nexus, a key tax issue, can also affect stranded cost estimates. Nexus refers to a right held by the state to levy state and local taxes on companies having sufficient property, employees, or other presence within the state. This issue is not limited to electricity sales—it pertains to any product or service sold by an out-of-state supplier. It is currently a matter of significant concern by state tax authorities and will ultimately be resolved in the court system.

If current suppliers of electricity in North Carolina (“incumbents”) face competition in the future from out-of-state suppliers, and if nexus cannot be established for tax purposes, the competitive price of power will be lower than it would be if nexus were established. Thus, stranded costs will be higher in the absence of nexus than if
nexus is established. In our analysis, we estimated stranded costs under both “nexus” and “no nexus” cases. We also estimated the tax effects of restructuring North Carolina’s electric utility industry for both nexus and no nexus cases in our companion report entitled State and Local Tax Considerations in Electric Industry Restructuring (RTI, 1999b). We used the “no nexus” assumption as part of our reference case.

3.3.7 Summary

All of these key issues can significantly affect the estimates of stranded cost amounts and are essentially policy issues that must be established by policy directives or resolved in formal (e.g., legislative, regulatory, or judicial) proceedings. We developed stranded cost estimates for the reference case; then we examined how sensitive the stranded cost results are to variations in the outcomes of these issues. These results are presented in Volume 3, Section 4. We prepared the reference case and sensitivity analysis results with the aid of an Excel spreadsheet program. This software program is flexible, allowing the user to change the values of the variables that are contentious and that can significantly affect the stranded cost results.

These issues do not address the recovery of stranded costs. Stranded cost recovery introduces other policy issues that are discussed in Section 4.2.
4 Stranded Cost Recovery

The previous section focused on the estimation of stranded costs and key issues in the estimation process. This section discusses the recovery of these stranded costs and key policy issues that need to be considered and resolved.

4.1 OVERVIEW

Basically, there are three stakeholder sources of funding for stranded costs:

- investors and creditors,
- ratepayers, and
- taxpayers.

Investors and creditors include stockholders, bondholders, and other long-term lenders. Investor-owned utilities (IOUs) rely on stockholders and bondholders for external capital. Publicly owned utilities (e.g., the municipal power agencies [MPAs] under ElectriCities) rely exclusively on bondholders for external capital, and customer-owned utilities (e.g., NCEMC) rely exclusively on long-term lenders.

Investors may become a funding source if full recovery of IOU stranded costs is not allowed from either ratepayers or taxpayers. Any such mitigation may lead to a reduction in the value of IOU stock, particularly if the mitigation is large relative to the IOU’s total asset value. These losses are attenuated somewhat by a lower income tax liability. As a result, taxpayers become an unwitting source of stranded cost recovery, either through tax increases.
elsewhere to maintain public services or through a decline in the quantity and quality of public services. This “recovery process” from investors and taxpayers is common in other industries, where losses (the term that is used instead of stranded costs) are reflected directly in writedowns of asset values.

Bondholders may suffer a reduction in bond values if the mitigation is large enough to affect the risk of default. They will suffer the loss of their remaining principal if default occurs. Long-term lenders may have to increase reserves to cover a higher risk of default on their loans, thereby reducing the effective rate of interest they realize. If default occurs, they will have to write off the loan balance in full. Losses to individual bondholders and private lenders are attenuated somewhat via lower tax liabilities, with the result again that taxpayers become an unwitting source of stranded cost recovery. Losses to public lenders (e.g., the Rural Utilities Service of the U.S. Department of Agriculture) are similar to a loss in the tax revenues that fund these public agencies.

Ratepayers are affected by stranded cost recovery if these costs are recovered through electric rates. The period over which stranded costs are recovered through rates is called the “transition period.” For any given level of stranded costs to be recovered through rates, a shorter transition period will result in higher electric rates during the period. Ratepayers suffer a loss in the purchasing power of their income, which may affect their purchases of other goods and services and their rate of savings.

Taxpayers can be affected by stranded cost recovery if investors and creditors are affected, as noted above. They can also be affected if less than full stranded cost recovery is allowed, because the taxable income of these utilities will fall as their revenues fall, unless these utilities can expand their sales revenue. An expansion in sales revenue is possible if a utility is a low marginal cost producer and can sell enough power to more than make up for the reduction in price (from a regulated to a competitive environment).

### 4.2 KEY ISSUES

Three major policy issues are associated with the recovery of stranded costs and they can affect all three stakeholder groups mentioned above. These major policy issues are as follows:
How much stranded cost recovery will be allowed from ratepayers? A corollary to this question is how should total stranded costs be allocated among utility retail customers (ratepayers), shareholders and creditors of the utilities, and taxpayers?

How should the portion recovered from ratepayers be allocated to different customer classes?

What cost recovery and true-up mechanisms should be used to share risks between the utility and its customers and to promote competitive generation markets?

### 4.2.1 Stranded Cost Allocation to Major Stakeholders

A distinction can be made between strandable costs, which can be reduced, and stranded costs, which cannot. Strandable costs are costs that can be mitigated by utility actions (i.e., managed) before they become stranded. An example of strandable costs is an expensive contract that can be successfully renegotiated to reduce total costs (including penalties) when that contact is up for renewal.

We estimated stranded costs at the retail level in this study. Because they reflect sunk (i.e., past) costs and future obligations that are related to the years when utilities were subject to rate regulation, stranded costs cannot be eliminated. Their recovery can simply be allocated to different groups of stakeholders. Regulators can allocate these costs among different groups, such as utility shareholders, bondholders and lenders, retail customers, and taxpayers. In other cases, costs can be shifted through time. There are several market, depreciation, rate design, and cost reduction strategies that might be considered.

One strategy, delaying competition during periods when the competitive market price of power is below the regulated price, protects utility shareholders at the expense of retail customers who lack alternatives. On the other hand, rapid and comprehensive implementation of retail competition could have serious financial effects and possibly bankrupt some utilities, unless some recovery of these costs from retail customers is allowed.

Other strategies, such as changing the depreciation schedules for generation and transmission assets, affect the timing of these costs.

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1It is true, though, as mentioned in Section 3, that the aggregate estimates of stranded costs may vary dramatically along with changes in key assumptions needed in their calculation.
rather than their amounts. For example, accelerating depreciation of a nuclear unit would increase rates for today’s customers and lower rates for future customers.

Several rate-making options (e.g., marginal cost pricing and performance-based ratemaking) are available currently, but they may need to be reconsidered as a means to help allay problems with stranded cost recovery. These options attempt to emulate a competitive market (or a more competitive market) and bring about some of the benefits of retail competition to customers prior to the start of retail competition. They are to some extent a substitute for retail competition, not in terms of customer choice, but possibly in terms of their effects on rates.

Finally, utilities may be able to cut their costs of producing, transmitting, and delivering electricity, as well as their customer service and administrative costs. Through the use of a sharing mechanism, the regulatory commission could allocate some of these savings to offset stranded costs with the remainder flowing to retail customers. North Carolina IOUs have been developing and re-engineering where feasible to reduce costs for several years, so the potential for further cost savings of this type may be limited.

### 4.2.2 Stranded Cost Recovery from Ratepayers

After determining the amount of money the utility will be permitted to collect from retail customers, regulators must consider how those funds are collected and from whom. With respect to allocation of costs among customer classes, regulatory commissions typically seek to prevent cost shifting among customer classes. That policy leads to a stranded cost allocation on the basis of the historical assignment of generation costs to each customer class. Typically, the cost-of-service research supporting the utility’s last rate case is the basis for assigning stranded costs to each class. This approach may cause controversy if customer load shapes or the utility’s generation costs have changed substantially since the last rate case.

Having determined how much money to collect from each customer class, the regulatory commission must then decide whether to collect that money through the

- monthly customer charge ($/customer-month),
- energy charge (¢/kWh), or, where applicable, or
- the demand charge ($/kW).
These costs are typically collected through the energy charge alone or through a proportional adjustment to all elements of the rate structure. If these costs are collected through the energy charge, the \$/kWh charge will differ across customer classes to reflect their differences in load shapes, voltage level of service (and, therefore, transmission and distribution system losses), and historical cost assignment. If these costs are collected through proportional adjustment to all elements of the rate structure, each component of a customer’s rate structure is increased by the same percentage. Recovery through the energy charge is susceptible to revenue erosion as customers reduce their energy use in response to high prices. Recovery through demand or customer charges is often preferred because these charges are not as easy to “bypass,” so there will be less effect on revenues. They are also preferred because they are considered more economically efficient, in the sense that they do not affect customer behaviors as much.

Finally, the regulatory commission will need to decide how to treat cases such as customers that self-generate much of their electricity and rely on the utility only for backup services, new customers that move into the service territory, and customers that leave the service territory. Customers who self-generate are more of a challenge for stranded cost recovery determinations than are the other two cases. Typically, new customers in a rate class pay the same stranded cost charges that existing customers in that class pay. As a practical matter, it is not feasible to recover stranded costs from customers who leave the service territory.

4.2.3 True-up Mechanisms

As discussed earlier, estimates of stranded costs prior to retail competition are likely to be subject to some error. Therefore, the regulatory commission may want to implement a true-up mechanism to adjust stranded cost recovery for differences between the assumptions prior to competition and actual events afterward. The regulatory commission might consider the following four broad goals and supporting objectives in selecting a true-up mechanism:

- The utility’s operation of, and investment in, its generating resources should be consistent with the actions taken by the owners of similar resources in fully competitive bulk power markets. Thus, the stranded cost recovery and true-up mechanism should not affect generation-related operation
and investment decisions. This general principle leads to three subsidiary objectives.

✓ The utility should be fully responsible for all future avoidable costs. That is, the recovery mechanism should not indemnify the utility for its future generation-related fuel costs, operating and maintenance costs, or capital costs; nuclear decommissioning costs will likely be an exception to this rule.

✓ The utility's earnings should respond to external forces (such as market prices) in the same way as earnings for other suppliers.

✓ The utility should have economic incentives to cut costs. Thus, some of the money saved by productivity improvements should be retained by the utility.

➤ Retail customers should benefit from competition and should face market forces. This principle leads to two subsidiary objectives, which may conflict with each other.

✓ Retail customers should face market-induced price changes.

✓ Future (market-based) retail prices should not exceed today’s embedded cost prices during the stranded cost recovery period.

➤ Neither customers nor shareholders should bear undue risks of over- or underrecovery.

➤ The mechanism should be simple to understand and to administer. It should not create the equivalent of heavily litigated, annual rate cases.

Regulators have many choices for true-up mechanisms:

➤ Securitization of stranded cost recovery amounts. Securitization is the issuance of bonds by a state agency, for which the state guarantees that utility customers will pay the interest and principal. Because of this state guarantee, these bonds are low in risk and therefore carry an interest rate lower than that for investment-grade corporate bonds. The utility receives the full bond proceeds when the bonds are issued and then, on behalf of the bondholders, collects interest and principal payments from its customers on a monthly basis. The only reconciliation associated with such bonds occurs if the monthly collections of principal and interest payments do not match those called for in the bonds; that is, the bondholders have a virtually ironclad guarantee of recovering their investment from electricity consumers within the utility's jurisdictional boundaries. (Adjustments to the monthly payments are symmetric. If retail electricity use is higher than expected, the payments are reduced and vice versa.) For North Carolina the value of securitizing stranded costs is limited, however, because most of the stranded costs are associated with MPAs, not
IOUs. Both state and MPA debt carry low interest rates because interest payments on both are tax exempt to the holder of that debt.

- Exit fees for departing customers (customers who switch suppliers). Exit fees require these customers to make a lump-sum payment (or a periodic stream of payments with the same net present value [NPV] as the lump-sum payment) to the utility for the stranded costs associated with those customers’ decisions to purchase its energy and capacity resources elsewhere. This is the approach that Federal Energy Regulatory Commission (FERC) uses for recovery of wholesale stranded costs.

- An up-front determination of (a) the amount of stranded costs that a utility is entitled to recover and (b) a cost-recovery mechanism that ensures that the utility, over time, recovers no more and no less than that predetermined amount. Periodic true-ups and balancing accounts could be used to adjust the monthly transition charge that customers pay for changes in load growth and any other factors that affect the amount of money so recovered. Because this approach predetermines the amount of utility recovery, it should be simple to administer.

- Full (100 percent) recovery of stranded costs. Full recovery assures the utility that it will recover dollar-for-dollar its actual stranded costs. This approach requires periodic (e.g., annual) true-ups to ensure that the utility recovers fully the difference between its embedded costs per kWh and the market price of generation. Such a system does not provide an incentive to the utility to mitigate stranded costs to the extent it can unless cost or productivity standards are continued or established for the first time.

- Prior specification of the retail price for generation services. This price could be capped at the current regulator-approved price or cut by a predetermined percentage. The utility is then allowed to collect stranded costs from its customers on the basis of the difference between the set price and its actual, ongoing costs of generation. No true-up is conducted with this approach.

- An after-the-fact reconciliation of stranded costs with a shared-savings mechanism. In this case, the utility would recover a predetermined percentage of the difference between its embedded costs of generation per kWh and the market price of generation. This system provides an incentive to the utility to cut costs and improve productivity because the utility is able to keep a portion of these gains.

None of these approaches satisfies all the objectives listed above. The first three mechanisms (securitization, exit fees, and use of an upfront determination) have similar characteristics. Specifically, they are simple to administer, primarily because they involve no
true-up or the amount of true-up is simple to determine. On the other hand, these methods provide no direct benefits to customers and may offer little incentive to the utility to cut its future generation costs. As FERC (1996) noted, “The primary rationale offered in support of a snapshot approach is certainty; the primary rationale offered in support of true-ups is accuracy.”

Assurance that the utility will recover 100 percent of its stranded costs helps insulate the utility from competitive generation markets during the stranded cost recovery (transition) period and therefore provides little incentive for feasible cost cutting or productivity improvements unless cost and performance standards accompany this assurance. Also, such a system would require frequent true-ups (e.g., annual) that examine a utility’s actual sales and power production costs.

Providing the utility 100 percent of the ongoing stranded costs associated with factors outside its control (especially bulk power market prices) would provide a clear incentive for the utility to improve its productivity because it does not adjust stranded costs for factors within the utility’s control (e.g., unit heat rates and availability factors). And this approach can be simple to administer, especially if a well-defined market price of power exists (e.g., the hourly spot prices published by the Pennsylvania-New Jersey-Maryland Interconnection, the independent system operator in the mid-Atlantic region).

The last two methods listed above provide productivity incentives to the utility and price reductions to customers. However, these methods are more complicated to design and implement and could lead to litigation every time the method is applied (e.g., the equivalent of an annual rate case). In addition, these methods place the utility at risk for nonrecovery of some of the stranded cost amount.

### 4.3 STRANDED COST RECOVERY OPTIONS

Because there are so many dimensions to stranded cost recovery, the total number of possibilities for stranded cost recovery is very large. To simply matters, we selected three basic stranded cost recovery options for this study:
Option #1 (Full Pooling): Stranded costs of all North Carolina utilities are pooled and recovered from all North Carolina ratepayers.

Option #2 (Partial Pooling): Stranded costs for Duke and North Carolina Municipal Power Agency 1 (NCMPA1) are pooled and recovered from ratepayers of both utilities. Stranded costs for Carolina Power & Light (CP&L) and North Carolina Eastern Municipal Power Agency (NCEMPA) are pooled and recovered from ratepayers of both utilities. Stranded costs for North Carolina Power are recovered from its ratepayers and stranded costs for NCEMC are recovered from its member co-ops and their retail customers.

Option #3 (Own Recovery): Each North Carolina utility recovers its own stranded costs.

Option #1 is the proposal ElectriCities submitted originally. Option #2 pairs MPAs with the IOU in whose generation resources they share ownership. Past generation investments are a large share of MPA stranded costs. Also, each MPA buys its additional power requirements from the same IOU (NCMPA1 from Duke, and NCEMPA from CP&L) (i.e., these MPAs are currently “full power requirements” customers of these IOUs) so any stranded costs associated with above-market power purchase contracts are tied to purchases from these same IOUs. NCEMC, which owns a share of Duke’s Catawba plant as does NCMPA1, buys power from both Duke and CP&L. For that reason, NCEMC was not paired with either IOU in Option #2.

Option #3 is a standard option for stranded cost recovery in other states that are considering this issue.

Recovery through rates was estimated for the full amount of stranded costs (i.e., 100 percent recovery) over 5- and 10-year recovery (transition) periods. Because stranded costs are very sensitive to the benchmark market-clearing price of power, and because that price varies by whether new entrants from out of state can be taxed, we included both “nexus” and “no nexus” cases in our illustrative calculations of stranded cost recovery through rates.
References


Appendix A: Bibliography
A.1 GOVERNMENT DECISIONS AND REPORTS


FERC’s Orders 888 and 888-A contain important discussions and findings on stranded costs resulting from certain wholesale electricity transactions. These orders review and summarize the many and disparate comments that parties filed with respect to stranded costs. FERC sets an important precedent by finding that utilities should be allowed to recover all legitimate, prudently incurred, and verifiable stranded costs. FERC also presents its Revenues Lost (a top-down) approach for use in estimating stranded-cost recovery.


A comprehensive and readable state rule on restructuring. The section on stranded costs (pages 222-309) discusses the basis for stranded cost recovery, including DPU authority to order retail access, legal claim to entitlement for stranded cost, policy for stranded cost recovery; entitlement to recovery for purchased power agreements; calculation of stranded cost; mitigation approaches; and stranded cost recovery mechanism.


Lengthy, comprehensive report on wholesale and retail sources of stranded costs in Texas; market methods to quantify stranded costs (spin-down, spin-off, open auction, open all-source solicitation for power requirements); administrative valuation methods and examples of such studies; financial considerations associated with stranded cost recovery (effects on common equity, bonds, income taxes, and local taxes); public utility commission (PUC) staff results for each Texas utility; and alternative cost-recovery methods and true-up mechanisms. An April 1998 report updates the staff stranded cost estimates for each utility.
A.2 STRANDED COST AMOUNTS


An update of an earlier (August 1995), widely cited study reporting national and utility-specific estimates of stranded costs. These results were developed using an administrative, ex ante approach for each major U.S. investor-owned utility. A key feature of this approach is the development of market prices for energy and capacity for each North American Electric Reliability Council (NERC) region.


A comprehensive report (available only through purchase from RDI) with detailed utility-specific estimates of stranded costs based on RDI’s bottom-up approach. The Inter-Regional Electric Market Model is the heart of RDI’s method; IREMM has a production-costing feature that simulates utility operation, including generator dispatch, maintenance scheduling, bulk-power transactions among utilities and nonutilities, and cost accounting.

A.3 POLICY ISSUES


Included with EEI’s response to FERC Notice of Inquiry on stranded costs, these three leading economists say that utility investors should not bear these stranded costs. Paper argues that both equity and efficiency considerations require that utility shareholders be compensated for past
decisions either ordered or approved by regulators. “Recovery of stranded costs can be compatible with efficient competition if the recovery mechanism is properly structured, so that the outcome of competition between rival suppliers will be determined on the basis of which is truly more efficient.”


A review of the major issues related to stranded costs: economic principles, market and administrative valuation approaches, criteria to use in assessing alternative valuation approaches, comparison of different administrative top-down and bottom-up approaches, key factors that affect stranded cost estimates, mitigation approaches, allocation of stranded costs among various groups, and integration of cost-recovery with competitive generation markets.


Primarily a legal argument against the notion that utilities and PUCs (acting on behalf of customers) have any kind of “regulatory compact” or “bargain” that requires PUCs to permit utilities to recover 100 percent of their stranded cost. Bradford finds no evidence that there ever was a regulatory compact that guaranteed full cost recovery. To the contrary, he finds many PUC and court decisions that allow utility shareholders to lose money on some uneconomic investments. Article makes four points: (1) there never was a regulatory compact; (2) investor have long been aware that serious losses were possible, (3) investors for many years have been compensated at levels high enough to cover the risks of some loss on strandable investment, and (4) not all strandable investments were prudently incurred.


Chapter 16 of this book, “Stranded Costs,” discusses the types of assets and liabilities that may become stranded, estimates of stranded costs for the United States as a whole, whether nuclear decommissioning should be considered a stranded cost, the arguments for and against stranded-cost recovery, the role of the “regulatory compact,” and government policy decisions on this issue.

Rose argues strongly that recovery of stranded costs by utility shareholders is not supported on grounds of either economic efficiency or historical regulatory policy. The concept of stranded costs, and arguments for its recovery by utility shareholders, has little basis in economic theory, legal precedence, or precedence in other deregulated industries.


The first two articles offer very different perspectives on the importance of the form and structure of auctions. The third article is the most useful. It reviews the auction format used by utilities to date, which calls for only one round of sealed bids. It suggests that a “simultaneous ascending auction” is a preferred approach. This approach was used by the U.S. Federal Communications Commission (FCC) to auction off parts of the electromagnetic spectrum. The primary problem with the single-round sealed bid approach is that it likely will not maximize the revenues from the auction, in part because of the winner’s curse and in part because bidders may not be able to assemble the portfolio of resources they are most interested in acquiring.


These articles include (1) a technical presentation of the perspectives of the securities industry (Abbott is with Moody’s), and some of the complexities in setting up the securitization; (2) an argument from a utility with a
significant stranded cost problem that, regardless of one's view on stranded cost recovery, you should favor securitization as a low-cost way to recovery these costs; (3) an argument from a state attorney general who opposes securitization because of its anticompetitive effects, including predatory pricing; (4) an argument from a low-cost utility in opposition to stranded cost recovery and especially to securitization; and (5) a technical article covering statutory, regulatory, bankruptcy, tax, accounting, and corporate securities issues related to securitization.

A.4 COST RECOVERY


A review of the key public-policy goals associated with cost recovery and true-ups and of mechanisms to meet these objectives; quantitative analysis of the effectiveness of seven mechanisms in meeting six goals for a hypothetical utility.


Joskow argues that stranded-cost recovery need not conflict with efficient competition. He emphasizes that decision makers must deal with stranded cost measurement and recovery at the time restructuring proposals go into effect to avoid cost shifting and inefficient competition. He presents a cost-recovery mechanism that will promote only economic bypass of existing suppliers; that is, generators and consumers will make operating and purchase decisions, respectively, independent of the amount of stranded costs. The mechanism derives from the economic distinction between fixed and variable costs in estimating the competitiveness of generating assets and in estimating stranded costs. The mechanism provides for recovery of sunk costs in excess of market prices, while allowing suppliers to compete on the basis of their avoidable costs.
Appendix B: Stranded Cost Recovery Decisions in Other Jurisdictions (as of Summer 1998)
Not surprisingly, opinions differ greatly on whether utilities are entitled to full recovery of their stranded costs.¹ Large industrial customers, consumer advocates, and some regulators argue that there is no constitutional entitlement to the recovery of such costs; indeed these costs should be subject to the same types of prudence and used-and-useful criteria that commissions have long applied to utility actions. On the other hand, many utilities argue that the Takings Clause of the U.S. Constitution requires full compensation for such costs; they also note that these costs were incurred with the approval, and sometimes at the mandate, of regulators.

Because of the large dollar amounts associated with stranded costs, state and federal regulators are committing considerable time and attention to stranded costs. At the federal level, the Council of Economic Advisers favors utility recovery of stranded costs:

... there is an important difference between regulated and unregulated markets. Unregulated firms bear the risk of stranded costs but are entitled to high profits if things go unexpectedly well. In contrast, utilities have been limited to regulated rates, intended to yield no more than a fair return on their investments. If competition were unexpectedly allowed, utilities would be exposed to low returns without having had the chance to reap the full expected returns in good times, thus denying them the return promised to induce the initial investment. A strong case therefore can be made for allowing utilities to recover stranded costs where these costs arise from after-the-fact mistakes or changes in regulatory philosophy toward competition, as long as the investments were initially authorized by regulators. ... To be sure, utilities should be granted recovery only of costs prudently incurred pursuant to legal and regulatory obligations to serve the public.

The Clinton Administration’s proposed Comprehensive Electricity Competition Act also favors utility recovery of stranded costs. Section 101 requires state regulators to address utility stranded costs “that are legitimate, prudent, and verifiable, if the utility has

¹When utilities suffer a financial loss (e.g., by earning a lower return on equity for stranded generating assets or by writing off some of these assets to reduce the amount of stranded costs to be paid by customers), this loss reduces their federal and state income taxes. Thus, taxpayers typically shoulder about 40 percent of any stranded costs borne by utility shareholders.
taken all reasonable steps to mitigate the costs.” The section limits stranded costs to those incurred before the date of enactment of this federal legislation.

The Federal Energy Regulatory Commission (FERC), in its Order 888, clearly favors utility recovery of “legitimate, prudent, and verifiable [wholesale] costs.” Although FERC decided to allow utilities the opportunity to recover 100 percent of the costs stranded by increased transmission access, FERC limited these opportunities to those that are a direct consequence of its actions. Similarly, the California public utility commission (PUC) and the California Legislature decided to allow utilities the opportunity to recover their retail stranded costs.

The California Legislature decided that all retail customers will pay for stranded costs through a nonbypassable competition transition charge, allocated across rate classes in a manner similar to the cost allocation in place as of June 1996. The California legislation is important because it provides the utilities with strong assurances for recovering a substantial portion of their stranded costs, and it “securitizes” some of these costs in a way that reduces the magnitude of stranded cost recovery (basically by replacing the utility cost of capital with the cost of new debt service to the State of California).

In a June 1998 decision, the Arizona Corporation Commission strongly encouraged the utilities to sell or spin off their generation assets to mitigate and measure stranded costs. The Commission stated that “the opportunity for full stranded cost recovery should be available only to those Affected Utilities that choose to divest. For Affected Utilities who do not divest, [the Commission may] authorize revenues sufficient to maintain financial integrity, such as avoiding default under currently existing financial instruments ... [based on] the minimum financial ratios to maintain financial viability for ten years ... .” The Connecticut Legislature, in an April 1998 law, was even more forceful in its support of divestiture. It allows stranded cost recovery only if the utilities divest both their nonnuclear and nuclear generation.

Commissions can apply different recovery levels for different types of stranded investments. They can consider the degree of utility management responsibility for the stranded costs that exist in each
category. In addition, the stranded costs associated with utility-owned generation assets include both a return of investment and a return on investment; PUCs can consider these types of costs differently for recovery purposes. They may allow either no or a reduced return on equity on certain assets contributing to stranded costs, for example. Alternatively, commissions may allow only a return of capital without any return on investment. Under this policy, shareholders would forego their equity return.

The New Hampshire PUC and the Vermont Public Service Board adopted stranded cost positions more favorable to customers and less favorable to utility shareholders than did FERC or California. The New Hampshire PUC noted that, with the exception of purchases from qualifying facilities, the “New Hampshire electric utilities’ historical prerogative to make resource decisions have not been significantly compromised by legislators or regulators.” The Commission proposed to use New England regional electric rates as a key element in determining the amount of stranded costs that individual utilities could recover. That is, the utilities in the worst financial shape, as measured by their retail rates, will get the least relief in stranded cost recovery. Specifically, the Commission stated that “it is our preliminary view that utilities with rates at or below the regional average should be provided a greater opportunity to recover net, verifiable, nonmitigable stranded costs than should utilities with rates above the regional average.” The Commission reasoned that each New Hampshire utility operated under comparable economic and regulatory conditions. Given these similar operating environments, one can assume that differences in utility rates are attributable primarily to utility management decisions. This decision was still in litigation in spring 1999.

The Vermont Board notes that the transition to competitive electricity markets may provide “substantial opportunities for utilities,” which can be used to offset what would otherwise be stranded costs. The Board also plans to limit stranded cost recovery to a 5- to 10-year transition period. It emphasizes the utilities’ obligations to mitigate stranded cost amounts and offers to provide stranded cost recovery only after all mitigation strategies have been implemented. The 11 mitigation strategies identified by the Board include renegotiation of power purchase contracts; buy out or buy
down of power purchase contracts; economic operation of existing facilities and contracts; shutdown of uneconomical generating units; renegotiation of fuel-supply contracts; cost reduction; sale of uneconomical assets; write-off or write-down of uneconomical assets; appropriate load growth; exchange of underutilized assets; and refinancing of obligations through low-cost, long-term bonds.\(^2\)

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

Practically, it might be very difficult to implement a new industry structure without the support of utilities. If utilities were not permitted to recover most of their stranded costs, they could find many ways to delay implementation of competitive markets. For example, lawsuits filed by Northeast Utilities concerning stranded cost recovery in New Hampshire and by PECO Energy concerning stranded cost recovery in Pennsylvania have stalled progress in those two states. The PECO lawsuits led to a settlement agreement and were dropped upon approval by the PUC. Thus, we anticipate that utilities in many jurisdictions will be allowed to recover most of the stranded costs that they cannot reasonably mitigate.

Consumers angry about perceived utility “bailouts” in Massachusetts and California tried to overturn legislative and PUC decisions that allow utility recovery of stranded costs. The Massachusetts Department of Public Utilities had taken a pragmatic view in its December 1996 restructuring order:

\(^2\)Some of these 11 strategies may not be strictly mitigative. Specifically, economic operation, shutdown of uneconomical generating units, and cost reduction overlap; write-offs, write-downs, and exchanges of underutilized assets shift costs to utility shareholders.
... the legal question of whether stranded costs are recoverable in the restructuring of the electric industry is one that PUCs and the courts have never addressed, let alone resolved. It continues to be our belief that litigation over stranded cost recovery would delay the introduction and benefits of competition for consumers. Furthermore, as a matter of sound public policy, the Department reaffirms that allowing electric companies a reasonable opportunity to recover stranded costs is in the public interest because such recovery would: 1) ensure the provision of sound electric services during the transition to competition; 2) affirm reliability of commitments, which is an essential element in any future industry structure; 3) promote federal and state coordination and ensure equal treatment of similarly situated utilities; and 4) avoid costly, reform-delaying litigation.

Massachusetts legislation passed in November 1997 essentially confirmed the Department’s approach to the treatment of stranded costs. In deciding how much stranded costs a utility is entitled to recover from its customers, the Department will require full documentation on such costs from each utility, including sensitivity analyses. In response to anger among consumer groups about a perceived “bailout” of utilities, another ballot initiative was instigated in 1998. This initiative, which was a vote on whether to retain the 1997 restructuring legislation, passed (i.e. the 1997 legislation was retained) in November, 1998. Thus voters in Massachusetts and California decided to retain their earlier legislative plan for customer choice, industry restructuring, and stranded cost recovery.

A California ballot initiative would have lowered electricity prices an additional 10 percent, eliminated stranded cost recovery for utility-owned generation, and prohibited customer payment of interest and principal on the rate reduction bonds, presumably at the expense of utility shareholders. This ballot initiative was defeated in November, 1998 by a margin of approximately three to one.

The Pennsylvania General Assembly passed electricity competition legislation in December 1996, in which it granted the PUC considerable discretion to determine the amount of stranded costs that is “just and reasonable,” not necessarily 100 percent. The
legislation did, however, provide the 100 percent recovery of costs related to contracts with nonutility generators. The legislation specified a maximum stranded cost recovery period of 9 years, but it granted the PUC the authority to lengthen the recovery period. The PUC is to conduct annual reviews to reconcile actual to authorized cost recovery.

The Pennsylvania PUC, in response to this legislation, closely scrutinized utility stranded cost claims. In general, the PUC disallowed substantial portions of the utilities’ stranded cost claims and accepted the methods and results of other parties, in particular the state Office of Consumer Advocate. The utilities protested the PUC’s stranded cost determinations, both before the PUC and in federal and state courts. Ultimately, the parties to these stranded cost cases negotiated settlement agreements, which the PUC then approved.

PUCs generally limit stranded cost recovery to those costs that are “legitimate, prudent, and verifiable” as well as nonmitigable. The Montana Legislature required that these costs include only those that “have been previously allowed in rates or, if not previously in rates, ... determined to be used and useful to ratepayers ....” The Nevada Legislature limited recovery to those costs that are “documented in the accounting records” of the utility.

Some utilities have generating assets whose book values are below market prices. Although this situation of negative stranded costs (i.e., what one might call stranded benefits) has received little attention, regulators in some states will have to decide how to allocate these benefits between utility shareholders and retail customers. Presumably, the same principles that determine the allocations for positive stranded costs should apply to negative stranded costs. As noted by the staff of the Texas PUC, “In the transition to a competitive retail electricity market, to the extent utilities with positive [stranded costs] are granted recovery of such costs from ratepayers or otherwise, utilities with negative [stranded costs] should likewise be required to pass through to ratepayers the benefits of their low cost generation resources.”