CREATING
COMPETITIVE MARKETS
IN ELECTRIC ENERGY

A Comprehensive Proposal

Michael K. Block
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& Freedom Foundation
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Creating Competitive Markets in Electric Energy

As competition sweeps into America's energy industry, the critical public policy issue is how to restructure the rules of the game so as to make the most of the current opportunity. The Progress & Freedom Foundation is undertaking the design of a replacement model to create a vastly more competitive electricity market to replace the current legacy of Progressive Era regulations.

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I. INTRODUCTION AND RECOMMENDATIONS

During the last 20 years, competition has been replacing regulation in major sectors of the American economy, including transportation, natural gas and telecommunications. In each of these industries, the development of competition has followed its own path. In all cases, however, competition has been facilitated by the growing realization that, where any reasonable possibility of competition exists, economic regulation is an imperfect mechanism that generally does not serve the interests of the consumers it is intended to protect—that regulation generally has kept prices high and masked inefficiencies that are costly to the economy.

The movement toward competition in the electric power industry is a world-wide phenomenon. Where government ownership is the prevailing industry structure—which it is in most countries—this movement has taken the form of privatization of the industry’s assets. In recent years, a number of countries, including the United Kingdom, New Zealand, Norway, Chile and Argentina have taken significant steps toward privatizing and introducing competition into their electric power industries.

The United States is home to one-third of the world’s installed electric energy capacity. Investor-owned utility (IOU) assets are in excess of $500 billion and revenues of the electric power industry total about $200 billion annually. In the United States, electric power assets are largely privately owned, but
regulated as franchise monopolies. As is the case with the government-owned systems, the introduction of competition in the U.S. offers the promise of billions of dollars annually in economic benefits.

Innovation and Competition

In the U.S. electricity industry, the move toward competition increasingly is being driven by technological factors that create competitive pressures destabilizing to the regulatory structure. Due to significant advances in combined-cycle gas-turbine technology and low natural gas prices, the cost of new generation is about 3.5 cents/kWh and falling. Because of excess generating capacity, the current spot price of electricity is even lower.

The average price faced by electricity customers, on the other hand, is about 8.5 cents/kWh for residential customers, 5 cents/kWh for industrial customers, and 7 cents/kWh for customers as a whole. The gap between the cost of producing electricity and the price that customers pay, combined with large variations in prices between nearby jurisdictions, creates intense pressure to open up markets.

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The market structure implications of the gas-turbine technology, as well as other technologies that may be on the horizon, are enormous. As demand becomes sufficient for economies of mass production to be realized, the cost of producing electricity from small-scale generators is likely to decrease dramatically. With mass production, least-cost installed capacity may be between 1MW and 10 MW range, the range of many housing developments, factories, campuses and other institutions. But low-cost generation will be possible on a much smaller scale. Several companies are starting to market "microturbines" in the 25 kW to 50 kW range. A 25 kW generator is enough to run the central air conditioner of a large house.

These small-scale generating technologies can and already are being used by traditional utilities, for peaking as well as other purposes. But, they can also be used to bypass utility operations. As Charles Bayless, CEO of Tucson Electric Power has written: "In 10 years, it will be possible for a 7-Eleven Store

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2 Other technologies that appear to have no significant economies of scale include fuel cells, photovoltaic cells, internal combustion engines and wind turbines. See Robert J. Thomas and Thomas R. Schneider, "Underlying Technical Issues in Electricity Deregulation, presented at 30th Hawaii International Conference on System Sciences, January 7-10, 1997. Gas turbines of various sizes are furthest along in penetrating the market.


5 Stuart Brown, "Here Come the Pint-Size Power Plants," Fortune, April 1, 1996.
to install a small 'black box' that brings natural gas in and produces heating, cooling, and electricity.⁶

Traditionally, transmission and distribution have connected energy users to large-scale centralized generation facilities. The ability to construct low-cost, small-scale generation capacity, which is also environmentally friendly, makes it economical to move from this "central station" paradigm to a new "distributed generation" paradigm, with many small generating units operating at or close to the load, diminishing reliance on transmission and even distribution facilities.⁷

The distributed generation framework makes the natural gas pipeline network a competitor of the electricity transmission network—placing a ceiling of 3.5 cents/kWh or lower on the price of delivered electricity any place natural gas can be delivered. Substantial, albeit not complete, deregulation of the gas industry has been a facilitating factor. In effect, electricity transmission, long thought to be a natural monopoly, has in many regions become "contestable". This, obviously, has profound implications for how the industry should be restructured.

It is important to point out that the development of distributed generation does not mean that small-scale generators will displace existing large coal and nuclear generating plants, which offer the prospect of low-cost power for

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decades, if not generations, to come. But new generation capacity, when
needed, increasingly will come from a range of smaller units. Most importantly,
the availability of low-cost small-scale generation changes the competitive
structure of the electric power industry.

The Current Regulatory Framework

Over the last 60 years, the market for electric power has developed under
a pervasive regulatory framework. At the state level, utilities have been granted
exclusive local franchises and, in return, have an obligation to serve customers
in their territories. Because entry has been restricted, IOUs have been subject to
cost-based rate-of-return regulation by state public utility commissions (PUCs) in
order to assure that service is available to all retail customers at rates that are
reasonable and not discriminatory. As part of this, state PUCs have had the
ability to approve or disapprove any IOU decision that may affect the rates it
charges or the terms on which it provides service, including all investment
decisions and mergers and acquisitions.

At the federal level, the regulatory framework was established by two New
Deal-era pieces of legislation. Under the Federal Power Act of 1935, the Federal
Energy Regulatory Commission (FERC, previously the Federal Power
Commission) has the authority to regulate all wholesale power and interstate
transmission transactions. As these transactions have become more numerous in recent years, the federal role has become more important.

Under the Public Utility Holding Company Act of 1935 (PUHCA), the second New Deal-era law, utilities have been subject to structural regulation by the Securities and Exchange Commission (SEC). PUHCA was enacted for the purpose of restructuring a utility holding company structure that was believed to have become too complex and dispersed and therefore unaccountable to regulators. The Act required the simplification of utility holding companies into single "integrated public-utility systems." Under PUHCA, the 14 registered electric utility holding companies, which account for about 20 percent of investor-owned utility retail electric sales, require SEC approval to issue or sell securities, or acquire utility or nonutility assets.

Starting in the New Deal-era as well, a significant public power sector has developed at both the federal and the local levels. Public power, including the Tennessee Valley Authority (TVA), power marketing authorities (PMAs), and municipal and cooperative power now account for about one-quarter of power produced.

Two recent pieces of legislation also have had a significant effect on the current industry structure. The Public Utility Regulatory Policies Act of 1978 (PURPA) was designed to increase energy efficiency by increasing the use of cogeneration and renewable fuels. Under PURPA, utilities were, and still are, required to purchase power from qualifying facilities (QFs) at the utility’s avoided
cost. Because of errors in projecting avoided costs, some utilities have become locked into long-term contracts with QFs at prices well above those prevailing elsewhere. PURPA also has contributed to the development of a significant non-utility generation sector, which now accounts for about seven percent of total electricity supplies.

Finally, the Energy Policy Act of 1992 also has contributed to the development of wholesale competition in several ways. First, by providing for wholesale generators exempt from PUHCA (exempt wholesale generators or EWGs), EPAct made entry into generation by both non-utilities and utilities much easier. Second, EPAct required that utilities make their transmission facilities available to other generators selling in wholesale markets. FERC's recent Order 888 specifies the conditions under which access to transmission networks is to be provided.

The Costs of Regulation

Sixty years of a regulatory structure that allows utilities with relative ease to pass along the costs of its investments to its customers, combined with a series of fuel-use policies that have attempted to substitute the government's judgment for the market's, are reflected in an expensive and inefficient capital stock, excessive electricity prices, balkanized markets and a pricing structure
that underutilizes available capacity and misallocates power among alternative uses.

A franchise monopoly, insulated from competitive pressures, obviously has a much weaker incentive to avoid poor investment decisions than would be the case in a competitive market. Utilities usually have been able to incorporate the costs of investments (whether good or bad) in their rate base, and charge rates which cover those costs, although in recent years this has become considerably more difficult. The high rates needed to cover the sunk costs associated with investments that in hindsight have proven to be mistakes are now providing a major impetus to the development of competition, because customers want access to power at its (lower) marginal cost. At the same time, the fact that some of these costs cannot be recovered in a competitive environment is the basis of the "stranded cost" problem, which is an impediment to regulatory reform. The level of stranded costs is a very tangible indication of the failure of the current regulatory system.

Moreover, the existing capital stock is not efficiently utilized, because the current rate structure for electric power deviates from economically efficient pricing principles. First, the price of power often varies substantially from state to state. Such variation would not exist to the degree it does today in a competitive market. In the absence of barriers to competitive entry and pricing in retail markets, electricity prices across geographic areas would differ only by transmission line losses and possibly congestion constraints. Because
competition is restricted, however, power is not able to flow into areas where its value would be highest, resulting in a loss in economic efficiency.

In addition, the differential between peak and off-peak electricity rates is not as large as it should be, given seasonal, weekly and hourly variations in demand. Efficiency would be enhanced by reducing off-peak prices in order to utilize idle capacity, as long as prices remain above marginal operating costs.

The only available quantitative estimates of the costs of regulation (or, alternatively, the benefits of deregulation) are from a study sponsored by the Citizens for a Sound Economy Foundation (CSEF). CSEF has estimated that retail competition would save customers from $22.1 billion to $57.6 billion annually in the short run, and $107.6 billion annually in the long run. After deducting the reduced profits to producers, the CSEF study estimates the net gains to the economy at $1.9 billion to $7.5 billion annually in the short run and $24.3 billion annually in the long run.

According to a study by the NorthBridge Group, CSEF has overstated the benefits of retail competition. The NorthBridge study first points out that the customer savings estimates are misleading because they consist primarily of a redistribution from producers to consumers. But, the NorthBridge study also criticizes the CSEF study for overestimating the net economic gains from

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competition by (1) overstating the extent to which consumers could increase electricity usage in response to price declines, e.g., during off-peak periods, and (2) failing to adjust for the fact that much of the projected increase in electricity consumption would be at the expense of declines in consumption of other forms of energy. These factors are at the heart of the CSEF estimates. Thus, while the CSEF study is qualitatively correct about the benefits of competition, its estimate of the magnitude of those benefits is questionable and its emphasis on redistribution of gains is of concern.

Potentially the most important cost of regulation is the loss of innovation. This is the clear lesson from other industries, such as telecommunications. A market-driven system for power would foster the development of new technologies, including the combined-cycle gas turbine, that are improving the functioning of the electricity market and, at the same time, reducing pollution.

A Proposed Replacement Model

The availability of low-cost, small-scale generation technologies makes the electric power industry contestable, independent of how widespread their use actually becomes. The ability, using these technologies, to deliver electricity at

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3.5 cents/kWh or lower places a lid on the price that incumbent generators and transmitters in combination can charge.

This alters the way in which regulation can and should be approached. The current restructuring discussions, as indicated by FERC Orders 888 and 889, emphasize the importance of non-discriminatory open access to transmission, to facilitate the development of a competitive generation market. But restructuring should also promote the development of a competitive transmission sector, which is now also a possibility given the technological developments discussed here.

The fact that transmission will not be “perfectly contestable” is not a sufficient reason to develop a new framework for its regulation, which is the direction in which the industry is now heading. The regulatory models which propose placing the operation of the transmission network in the hands of an independent system operator (ISO) are based on optimistic assumptions about what will occur in a regulated transmission pricing environment.

Thus, the costs of regulatory failure must be weighed against the costs of market failure, which is why economists frequently are reluctant to recommend regulation when at least some significant competitive pressures are at work.\(^\text{10}\)

\(^{10}\) As Paul Joskow and Roger Noll observed in an influential survey article on the economics of regulation: “Because economic theory is firm in concluding that monopolies create economic inefficiency, social intervention to prevent, undo, or control monopoly is potentially attractive. However, because social interventions generate direct and indirect costs through the peculiar kinds of inefficiencies they cause, attempting to deal with monopoly may be at least as costly as leaving it alone.” (emphasis supplied). See Paul L. Joskow and Roger C. Noll, “Regulation in Theory and Practice: An Overview,” in Gary Fromm, ed., Studies in Public Regulation, MIT Press, 1981, p. 10.
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Competition should be encouraged where it is in the process of developing, as it is in both the generation and transmission markets.

If one of the principal goals of restructuring is rationalizing the power industry’s capital stock, then the pricing of transmission is of critical importance. Generation and transmission are already substitutes and will become even more so as competition develops. Market-based pricing of the transmission network is necessary to provide the correct price signals both for efficient dispatch and efficient investment decisions. Allowing transmission owners to receive the fair market value for their transmission assets also may help mitigate the stranded cost problem.

If transmission is deregulated, there inevitably will be concerns about the existence of residual pockets of market power. To alleviate these concerns, we propose a transitional short-run price ceiling for residential customers, which will assure that prices won't rise while the market is adapting, and a long-term regulatory fallback mechanism that would be available to address non-transitory market power concerns. These are described below, along with the other steps that need to be taken to implement competition in electricity markets.
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Implementation

Currently, there is no retail access in any state. Most states are considering the issue, but only three—California, Pennsylvania and Rhode Island—have thus far adopted plans establishing a date for retail access. Under FERC Order 888, utilities that own, control or operate interstate transmission are required to file non-discriminatory open access tariffs, providing for both point-to-point and network services, which will open the wholesale power market to competition.11

Starting from the current regulatory environment, the following steps (taken in the order presented) represent our view of how best to bring about a competitive marketplace in electric power:

1. **PUHCA and PURPA Repeal**

   The Public Utility Holding Company Act of 1935 (PUHCA) and the Public Utility Regulatory Policies Act of 1978 (PURPA) should be repealed at the

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11 With network service, the price is based on total customer load. The transmission user is permitted to use the entire grid to serve multiple loads without having to pay a separate charge for each pair of delivery point and load. There are no specific capacity rights associated with network service. With point-to-point service, the user designates points of delivery and receipt and makes capacity reservations for each of these point pairs. Point-to-point service involves clearly defined capacity rights. Simultaneous with the release of Order 888, FERC proposed to replace these two services with a single capacity reservation tariff, under which users would reserve rights to deliver and receive specific amounts of power at specific points on the grid.
earliest opportunity. Both of these steps would be procompetitive, independent of any other legislative action.

2. Public Power

The federal government should privatize its power assets and should discontinue its subsidies to public power. Tax, borrowing and other advantages conferred on municipal and other public power should be removed so as not to interfere with the emerging private competitive market. Specifically, we suggest that, beginning on a date certain, no municipality or other public power entity should be permitted to issue tax free bonds to build new electric plant, or restore or refurbish existing plant. Similarly, the federal government should not provide loans or subsidize borrowing for these purposes.

3. Adoption of Market-Based Generation Pricing

Wholesale generators should be deregulated as soon as possible. Evidence developed during the course of this project shows that it takes only a small number of generators to produce competitive results.\textsuperscript{12} Moreover, geographic markets for generation have increased in size, bringing in new competitors and reducing concentration. Finally, the new gas-generation

technologies that make entry relatively easy have made the generation market highly contestable.

Because of these factors, and since open access transmission tariffs are now required, there should be a presumption that generation at the wholesale level is competitive. In order to reimpose regulation, FERC should be required to show that competition in a specific market is insufficient.

4. **Elimination of Barriers to Interstate Commerce in Electricity**

A necessary condition for the creation of competitive electricity markets is the elimination of barriers to interstate commerce in electricity. This is also consistent with having a national market, which is basic to our federal system. Because electricity markets are now regional in nature, existing state regulation represents a significant barrier to interstate commerce. Interstate barriers could be eliminated by doing away with exclusive sales territories, as some states already are doing. Alternatively, they might be eliminated by creating truly competitive wholesale markets. For example, distributors (who might remain regulated at the local level) could be required to buy electricity for retail customers in the spot market. Large customers could be permitted to buy directly from generators in order to provide a benchmark competitive price. Retail prices might be directly tied to this benchmark, as is done in Chile.
5. Adoption of Market-Based Transmission Pricing

At the same time that states implement retail competition or otherwise remove their trade barriers, transmission prices should be deregulated. Competitive pressures on grid owners, from gas-turbine generation technology and elsewhere, are significant, notwithstanding the conventional wisdom that the wires business is a natural monopoly. Moreover, the regulatory frameworks proposed for transmission are likely to perpetuate the problems of the past.

6. Transitional Residential Price Ceiling

For a period of three to five years after transmission is deregulated, residential prices should be limited to their historic rate of change as measured over a recent period, for example, five or ten years. Depending on the period chosen, this would mean that the real price of electricity would be relatively constant and might even decline slightly. See Table I.1. Utilities could petition for relief from this ceiling in the event that it became inconsistent with their unavoidable costs (for example, if energy prices rose unexpectedly). At the end of the three-to-five year fixed period, the price ceiling would be lifted.
Table I.1

Average Price of Electricity Sold (cents per kWh)
Constant (1987) dollars

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<th>Total</th>
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<th>Commercial</th>
<th>Industrial</th>
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<td>1987</td>
<td>6.4</td>
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<td>7.1</td>
<td>4.8</td>
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<tr>
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<td>7.2</td>
<td>6.7</td>
<td>4.5</td>
</tr>
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<td>1989</td>
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<td>5.5</td>
<td>6.1</td>
<td>6.1</td>
<td>3.8</td>
</tr>
</tbody>
</table>

Source: U.S. Energy Information Administration, Annual Energy Review

7. **Regulatory Fallback**

Because there may be residual pockets of market power after the transitional price ceiling is lifted, it would be desirable for customers to have recourse to some regulatory mechanism in the event that prices at some locations were believed to be above competitive levels. The burden of proof in such proceedings should always be on the complainant and not the defendant.

If prices at most locations are competitive, as we believe they would be, it would be reasonable to evaluate a utility's price performance by looking at other similarly situated firms in demonstrably competitive markets.\(^{13}\) For example, an

\(^{13}\) See, for example, discussion of "yardstick" competition in Roger Sherman, *The Regulation of Monopoly*, Cambridge University Press, 1989, pp. 73-74.
external price benchmark could be developed on the basis of a statistical
analysis of other firms, taking into account factors such as climate, local fuel
costs and any other relevant price-determining locational differences. Based on
this benchmark, a two-step procedure could be established.

- First, customers would be required to show that electricity prices were in
  excess of the benchmark measure.

- If the benchmark test were passed, customers would then have to show that
  the market structure, taking into account actual and potential competition,
  was not sufficiently competitive.

Corrective action might be a price or a structural remedy. For example, a review
process could be established in which the utility would propose a solution along
the following lines:

- Establish separate generation and transmission subsidiaries or affiliates
  within the same company;

- Adopt market rules designed to avoid the problem. For example, a
  company could refrain from purchasing its own power at any price it was
  not willing to offer for power provided by other companies.

- Separate transmission and generation into independent companies.

  If no structural remedy were available to make the market competitive, the
  ultimate fallback position would be to reimpose some form of rate regulation.
8. **Stranded Costs**

The parameters of a solution to the stranded cost problem should be established simultaneously with the beginning of competition. Whatever deregulatory bargain is struck, a “market-based” approach should be used to value assets. Such an approach seems the best way to solve the stranded cost problem without lengthy regulation proceedings and without adversely affecting competition in the electricity industry.\(^4\)

9. **Social Goals**

In a competitive environment the costs of social goals, such as universal service, will be explicit and should be paid for by a broad-based tax on electricity consumption or from general revenues. Other goals, such as expanded use of renewable resources, can be pursued voluntarily by those who value and purchase them.

10. **Role of FERC**

FERC would administer the transitional price ceiling and the fallback regulatory mechanism. Its role in regulating transmission, which has been growing in recent years, would be dramatically reduced.

\(^4\) We will separately publish a specific market-based mechanism for valuing stranded costs.
11. **State Plans**

State plans should be grandfathered, except insofar as they erect or maintain barriers to interstate commerce.

**Outline of Report**

In Section II, we discuss the federal role in creating competition by eliminating barriers to interstate commerce in electricity. Section III contains a discussion of the innovations in gas generation technology and their implications for market structure and competition. Section IV provides the basis for our market-based transmission pricing proposal. Section V contains a discussion of the reforms in public power needed to complement a competitive restructuring of the power industry. Section VI provides the basis for our recommendation for repealing PUHCA. In Section VII, we discuss the problems associated with PURPA and our recommendations for its repeal. Section VIII provides a discussion of stranded costs.
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Note that none of the arguments concerning competition depend on the possibility of building new transmission capacity, which, because of state siting regulations, is generally considered to be very difficult. This situation can be improved, however, and construction of new transmission capacity made easier. For example, authority for the building of new transmission lines, including granting of eminent domain, could be shifted from the states to the FERC. This would be consistent with FERC’s existing authority over expansions of the natural gas pipeline system, and with FERC’s existing authority over electricity transmission, which generally is considered to be an interstate function. In addition, transmission owners using rights of way acquired under eminent domain might be required to make those rights available, at reasonable cost, to a potential entrant. This would provide additional discipline to the transmission owner’s pricing behavior. Recall that the threat of entry is sufficient to discipline prices. The actual building of new transmission capacity is not necessary.

Efficient Transmission Pricing

The transmission price between any two locations, A and B, is simply the difference between the delivered electricity price at A and the price at B. In the absence of congestion, this price should equal marginal line losses. When congestion occurs, the price difference between A and B should be larger than marginal line losses by an amount reflecting the opportunity cost of congestion—the costs incurred when more expensive plants are forced to operate due to "out-
of-merit order dispatch*. If the line carrying power from A to B is constrained, for example, the price at B should rise as dispatch protects the line from overload by allocating loads to higher-cost generators, supplying power at B. In that event, revenues from customers exceed payments to generators by more than the physical line losses.

Because of the physical characteristics of electricity, congestion in one part of the network can be caused by activities elsewhere. According to Kirchoff's laws, power follows the path of least resistance, moving along parallel paths and often taking a circuitous route to its destination. This "loop flow" characteristic differentiates electricity transmission from other transportation systems, such as highways, railroads and pipelines, and makes it difficult to define property rights in terms of a simple "contract path" between two points. Capacity on that path may not be available when needed, due to the actions of other parties, because power injected at any one location in the network may affect the availability of transmission capacity elsewhere. This physical characteristic of electricity networks has been used to justify the view that, quite apart from market power issues, the transmission system requires some form of centralized control.

Notwithstanding the problems associated with loop flow, it is, in theory, possible to price transmission efficiently. The question is whether in practice this objective is more likely to be achieved by a regulatory or a market-based transmission pricing system.
The Independent System Operator

The power industry is now moving toward a system in which operation of the transmission network, including pricing, would be placed in the hands of Independent System Operators (ISOs).\textsuperscript{4} ISOs across the country are in various stages of development, but none has yet started operating.\textsuperscript{5} They are intended to be agents of all the stakeholders in the market—generators, transmitters, consumers and the “public interest”—but beholden to none. In particular, ISOs would not have any ownership interest in generation or transmission assets. It is unclear what the ISO’s objectives would be, but there is no reason to expect them to have a strong incentive to price transmission services efficiently.

From an economist’s perspective, the ISO model does not sound very much like deregulation. In most ISO plans, the ISO would be responsible for all operational aspects of the transmission network: dispatching generation plants; charging locational spot prices; and administering a system of transmission congestion contracts to be used by market participants to insulate themselves and their customers from the effects of transmission constraints. This framework has been called the “Centralization of Authority” or “Maximum ISO” scenario by


\textsuperscript{5} With the exception of the ERCOT ISO, which is limited in scope, and started operation in January 1997.
Conference Draft

Thomas and Schneider (to be distinguished from the "Minimum ISO" scenario, in which the ISO has no authority over prices).  

In the ISO framework, the owners of the grid would receive a regulated payment to cover embedded costs and would not receive congestion rents. A system for distributing congestion contracts would be developed. For example, participants might be able to obtain congestion contracts by paying embedded costs (i.e., some administratively determined payment) to the grid owner or buying them in the secondary market. Holders of congestion contracts would receive the congestion rents collected by the ISO and thereby insulate themselves against the costs of congestion.

The ISOs would also be likely to have a direct role in transmission capacity decisions, although the mechanisms for making these decisions are not well defined. Whether ISOs would have the appropriate incentives to expand transmission capacity efficiently is, again, an open question.

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* Robert J. Thomas and Thomas R. Schneider, "Underlying Technical Issues in Electricity Deregulation," presented at the 30th Hawaii International Conference on System Sciences, January 7-10, 1997. As discussed below in this section, voluntary pools are routinely formed today, and could be under market-based systems, to efficiently coordinate activities.
Transmission Pricing Regulation in Practice—the California Experience

The California restructuring experience suggests that decisions within an ISO framework will be guided more by political than efficiency considerations.

Two competing transmission pricing proposals have been under consideration in California. A plan favorable to importing power from distant coal-fired generators has been proposed by the Western Power Exchange (WEPEX), an association of transmission owning utilities and other parties that will form the basis of the California ISO. The Coalition for Comparable Transmission (CCT), on the other hand, has proposed a plan more favorable to local gas-fired generation.

Regardless of the merits of the competing proposals, they are largely motivated by distributional rather than efficiency concerns. This, of course, is typical of regulatory proceedings.

Additional problems may be created by restrictions imposed on the California ISO. A recent analysis by Steven Stoft argues that operational restrictions will prevent economic (least-cost) dispatch of generation, reduce reliability by causing lines to be operated at their security limits (when it might be cheaper to operate them less fully loaded), and price congestion perversely.7

Who Receives the Congestion Rents When a Line is Constrained?—

Experimental Results

The attribute most critical to the success of a transmission network under ISO management is that it yield locational prices that accurately reflect marginal transmission costs, including congestion rents. If this is not the case, the entire framework will not allocate transmission and generation resources efficiently.

Under the ISO framework, electricity prices at the various locations are determined by the bidding behavior of generators and electricity customers, but there is no active quoting of transmission prices. The transmission price is simply the residual—the difference in the price of delivered electricity between any two nodes—and the transmission operator has no transmission pricing function.

The engineering optimization models assume that this framework will yield transmission prices that reflect congestion rents, but these models fail to take into account the behavior of the participants (sellers and buyers of electricity) in the market, as has been shown by research done at the Economic Science Laboratory reported in a paper by Backerman, Rassenti and Smith (BRS).

BRS conducted a series of experiments using a model of a three-node radial electricity network that looks much like the United Kingdom electricity network.
network, with two generating nodes serving a central consuming node. The transmission line between one of the generating nodes and the consuming node was constrained, while the other transmission line was not constrained. Each of the six generators (three at each node) and four buyers actively participated in the market, making asks and bids. There was, however, no similar activity with respect to the transmission function. Within this framework, BRS found:

- The generators at the end of the constrained line were able to behave strategically, increase their profit share and capture most of the transmission congestion rents.
- Generator profits were at the expense of the owners or operators of the congested transmission line, who receive less than half the congestion rents predicted by the engineering optimization model.
- Market efficiency—the percentage of the potential gains from trade actually realized—was reduced.

As BRS noted:

the congestion rental price of a constrained line can soar relative to marginal loss. This also suggests why the regulation, or ownership, of electrical utilities by political entities does not use opportunity cost principles in pricing transmission networks. In this case the unit opportunity congestion cost is almost 4 times the marginal loss price. Of course the economic function of these congestion rents is to signal the need for investment: investment to increase the transmission capacity of T1 [the constrained transmission line], to increase low cost generation capacity at node G2 [where transmission capacity is unconstrained], or to introduce

demand side management technologies that will conserve energy consumed by buyers at B. (emphasis added).

The BRS experimental results suggest that, because the transmission operator is not an active participant in the market, the ISO model is not likely to yield efficient prices. In that event, the prices it yields will send the wrong signals about how to dispatch existing generation capacity, and also the wrong signals about investment in new transmission and generation capacity and conservation measures. In contrast, preliminary experimental results show that, with market-based pricing, the costs of transmission constraints are more accurately reflected in transmission prices.

The Problems of Underpricing Transmission—The Argentina Example

Data from the Argentina electricity market are consistent with the economic experiments and illustrate some of the problems that develop when transmission prices do not reflect capacity constraints. The Argentina electricity system is operated by CAMMESA, an ISO jointly owned by the market participants and the state. Conceptually, this system is supposed to yield power prices that vary according to line losses and transmission constraints. Because transmission is not priced at its incremental cost, however, new generation capacity is being added in the Comahue region, which already has over 5,100

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9 Backerman, Rassenti and Smith, p. 9.
MW of generating capacity, much more than the 2,600 MW of peak transmission capacity connecting it to the major consuming area, Buenos Aires. Thus, uneconomic generation decisions are encouraged when transmission prices do not reflect congestion costs.

Competition with Market-Based Transmission Pricing

The above discussion suggests that the ISO framework is not likely to produce either efficient transmission pricing or efficient transmission and generation capacity decisions. It seems reasonable, therefore, to give serious consideration to a more decentralized market-based system for transmission.

Of course, a market-based system still needs to take into account the physical characteristics of the transmission system. However, the transmission owner, rather than an independent ISO, can undertake the major operational functions of the transmission system. One system that may emerge is the "buy-sell" model, described by Hogan as follows:

The "buy-sell" model is an alternative interpretation of the efficient short-run pricing system that accommodates the loop flow problem. In the buy-sell model, the grid operator stands between power generators and power consumers. Ideally, the operator buys and sells power at the buses at the short-run efficient prices. One great attraction of this perspective is that there is no need to define transmission at all; users of the network never transmit power across the network, they merely sell at some nodes and buy at others. The problems of loop flow and congestion are then

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hidden in the internal operations of the network. All transmission is implicit. If the bus prices are short-run efficient, then the implied transmission prices are just as used here—the difference between the short-run prices at the buses.¹¹

In the buy-sell framework, the grid owner would trade "delivered electricity"—offering to purchase at injection locations and to sell at withdrawal locations. As would be the case under any system, the operator would hold trading sessions for periods ahead of time. If the flow pattern associated with a given set of prices was not feasible, the operator would adjust prices accordingly. (The owner would have available the same models as would an ISO, with which to simulate the flow patterns associated with a given pattern of injections and withdrawals.) Prices would be lowered at any node where the supply of power became excessive or the demand insufficient. Similarly, prices would be raised any place the supply was insufficient or the demand excessive.

Generators and users could hedge against changes in the spot price of electricity using "contracts for differences". These contracts are the economic equivalent of long-term contracts for physical delivery and, as Hogan and others have shown, are the most obvious way to incorporate bilateral transactions into the system. In essence, a generator and customer contract for a specified amount of power at a given price, but there is no obligation to deliver the electricity. If the contracted price is lower than the spot price, the generator is obligated to pay the customer the difference. If, on the other hand, the

contracted price is higher than the spot price, the customer is obligated to pay the generator the difference.

Hogan suggests the buy-sell model would have difficulty gaining acceptance among network users because it wouldn't provide them sufficient protection against price changes due to congestion of the network. But the transmission owner could, for a price, provide guarantees of injection and withdrawal rights (and perhaps alternative levels of guarantee for different prices). The transmission owner could also sell transmission congestion contracts in the same manner as an ISO.

In fact, it is likely that contracts would emerge that simultaneously hedge against changes in the spot price of power and the costs of transmission congestion. These contracts would combine the functions of contracts for differences and transmission congestion contracts.

Efficient spot prices reflect the marginal cost of transmitting electricity. They consist of marginal line losses and congestion costs and do not necessarily cover the embedded costs of constructing the network. These latter costs would have to be covered and it is possible to envision several methods. The transmission owner could simply charge a fixed fee for access to the system. This is an efficient system that also has been suggested in the ISO context. Alternatively, the transmission owner might incorporate capital costs (along with line losses and congestion costs) directly into transmission prices, perhaps varying them inversely with demand elasticities. In this way, the market could
approximate a kind of Ramsey second-best pricing, which would recover fixed capital costs in an optimal manner.

In a decentralized, market-based system, the owner clearly has a strong incentive to internalize externalities within its own control area, because failing to do so involves a loss in profits. Owners of adjacent systems also will have incentives to enter into contractual arrangements with each other to internalize the externalities between control areas. Because each owner would only have to deal with a small number of adjacent control areas, transactions costs are not likely to be a significant barrier to the efficient internalization of externalities. If pools are needed to efficiently coordinate specific activities of a number of control areas, they can be established voluntarily, as they routinely are today.\(^{12}\)

Currently, there exist a variety of voluntary pooling arrangements, ranging from "tight pools", which operate essentially as single systems, including central dispatch of generating plants and coordination of capacity requirements, to "loose pools", which generally do not include central dispatch.

Finally, and importantly, there may be technological solutions to market organization problems. For example, the development of FACTS (flexible ac transmission systems) has potentially important implications for transmission economics.\(^{13}\) The FACTS technology will significantly reduce the cost of adding transmission capacity. But, it also can be used to control power flows and

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reduce the problems associated with loop flow. Thus, there already may be a feasible technological solution to the property-rights definition problems in electricity networks.

Summary

The potential costs of government failure and market failure should be carefully weighed against each other in determining whether transmission pricing should be market-based. Market-based pricing should be given serious consideration for two reasons. First, there are numerous competitive pressures on transmission owners. Most importantly, the gas turbine technology is rapidly eroding the transmission network's natural monopoly, which has provided the basic rationale for regulation. Electricity restructuring should take advantage of this important competitive development, in order to achieve the most efficient pricing system possible.

Second, there is no reason to believe we know how to operate a centralized regulatory system for the transmission network any better than the current regulatory system has been operated. The ISO has been presented as the ideal planning organization, with no economic interests or incentives except to run the transmission system and determine transmission prices in the public

interest. Since such organizations are few and far between, there is a large element of wishful thinking in believing that one is likely to appear now. ISOs will have enormous power, will be subject to FERC regulation, and will develop a set of incentives and patterns of behavior that are difficult to predict, but will not necessarily be consistent with efficient operation of the system. An inefficient regulatory system is likely to continue the misallocation of investment that has characterized the current regime.

Finally, the lesson from other industries, such as telecommunications, is that cost-based regulation is a serious barrier to innovation. A market-driven transmission system would foster the development of new technologies, such as gas turbines and FACTS, that are improving the functioning of the electricity market. There is a clear interaction between the economic needs of the marketplace and technological developments, which are likely to be more responsive to the market's needs in a market-based pricing environment that provides the appropriate incentives.

*Section 1 includes a proposal for a transitional price cap and fallback regulatory procedures to address residual pockets of market power.*
V. PUBLIC POWER

In contrast to most other countries, the United States traditionally has primarily relied on the private sector to produce and deliver electricity. Nevertheless, the role of public sector is still surprisingly large, with public power accounting for about 25 percent of all power generated in the U.S. (See Table V.1).

<table>
<thead>
<tr>
<th>Type of ownership</th>
<th>Number of Utilities</th>
<th>Number of Ultimate Customers (%)</th>
<th>Sales to Ultimate Customers (%)</th>
<th>Generation (%)</th>
<th>Installed Capacity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>IOU</td>
<td>249</td>
<td>75.6</td>
<td>76.2</td>
<td>75.4</td>
<td>75.0</td>
</tr>
<tr>
<td>Federal</td>
<td>6</td>
<td>0.0</td>
<td>1.6</td>
<td>8.5</td>
<td>9.0</td>
</tr>
<tr>
<td>Municipal and State Cooperative</td>
<td>2,015</td>
<td>13.6</td>
<td>14.4</td>
<td>10.5</td>
<td>11.7</td>
</tr>
<tr>
<td></td>
<td>937</td>
<td>10.8</td>
<td>7.8</td>
<td>5.6</td>
<td>4.3</td>
</tr>
</tbody>
</table>


The public power sector includes the federal power marketing administrations (PMAs), the Tennessee Valley Authority (TVA), municipal utilities, state power agencies, irrigation districts and electric cooperatives. While electric cooperatives are de jure private entities, the many features they share with municipal and state utilities (such as exemption from taxes and regulations) make them de facto members of the public power sector.

The relative importance of public power varies greatly across the country. Nebraska, which relies entirely on public power, leads the way, followed by Tennessee,
with 98 percent of all power consumed being publicly provided. Municipal and other public power systems also are common in the Pacific Northwest, Arizona, California and Texas. While municipal utilities typically serve small towns, they also serve some of the nation's largest cities including Los Angeles, San Antonio, Seattle, Memphis and Nashville. Cooperatives traditionally have played a significant role in rural areas, although with continuing urbanization, many of them now supply prosperous suburban communities.

Publicly owned utilities, because they are protected from competition and have no shareholders to satisfy, lack the appropriate incentives to minimize costs and operate efficiently. In addition, public power enjoys numerous indirect subsidies, not available to investor-owned electricity producers, which result in underpricing and inefficient use of electric power. Unless this is done, municipal, cooperative, state and federal utilities will enjoy unfair advantages vis-a-vis their private counterparts. As part of the move toward competitive markets, the federal government should privatize its power facilities and governments at all levels should remove tax, borrowing and other advantages available to publicly owned utilities.

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Federal Power

Through TVA and the PMAs, the federal government generates about eight percent of the electric power in the United States, making it the nation's largest producer of electricity. Although attempts have been made during the past decade to privatize some of these entities, the only PMA divested thus far has been the Alaska Power Administration, which was defederalized in 1995.

Federal involvement in the electric power industry is largely a byproduct of federal construction of navigation, flood control, water supply and irrigation projects. The five PMAs—Bonneville (BPA), Southwestern (SWPA), Southeastern (SEPA), Alaska (APA) and Western (WAPA)—were established between 1937 and 1977 to transmit and market electric power generated at federal hydroelectric projects. TVA's mission was much broader, as Franklin Roosevelt stated in his 1933 speech introducing the TVA Act before Congress: "It should be charged with the broadest duty of planning for the proper use, conservation and development of the natural resources of the Tennessee River drainage basin and its adjoining territory for the general social and economic welfare of the nation."

The PMAs, which are part of the Department of Energy, market power produced at hydroelectric dams built and operated by the Corps of Engineers and the Bureau of Reclamation. They are funded through annual budget appropriations, and their receipts

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from the sales of electric power are deposited in the Treasury. (BPA is an exception. In 1974, Congress stopped appropriating funds for Bonneville and instead established a revolving fund maintained by the Treasury and provided for permanent Treasury borrowing authority.\(^5\))

PMAs are required to set their resale prices at the lowest possible level consistent with sound business principles—that is, at prices high enough to cover costs without making a profit. Consistent with their original mission to provide inexpensive power to rural and underdeveloped regions, the PMAs sell most of their power to "preference customers"—municipal, cooperative and other public utilities located in the PMAs' marketing areas.

The legal and financial structure of TVA differs substantially from that of the PMAs. TVA is a corporation owned solely by the federal government. Its operations and investments are financed by cash receipts from power sales as well as long-term debt, which is capped at $30 billion by Congress. The debt is in the form of tax-free bonds, which are not formally guaranteed by the government. TVA does receive some congressional appropriations ($142 million in FY 1995), but their use is limited to non-power programs.

While there are few direct subsidies flowing to federal power, the indirect subsidies are large. Neither the PMAs nor TVA pay any federal, state or local income taxes or property taxes. By not requiring TVA to pay federal income tax, the Treasury is

\(^5\) There are other differences that make the PMA’s a non-homogenous group. For example, SEPA does not own any transmission facilities and instead markets power through other utilities' networks. APA is the only PMA that directly owns hydroelectric facilities. WAPA and BPA are required to recover in their electricity prices costs of irrigation that exceed the users' ability to pay.
foregoing $578.5 million annually. Other tax advantages cost federal, state and local
governments combined an additional $461.7 million annually. With respect to the
PMAs, the federal government would receive income taxes with a present value of
$1.013 billion if SEPA, SWPA and WAPA were privatized and allowed to compete.
The PMAs and TVA enjoy additional subsidies in the form of access to
government funds and guarantees which lowers their borrowing costs. TVA
bondholders, for example, are exempt from federal, state and local taxes on interest,
which lowers the interest rate needed to attract investors. TVA bonds enjoy a AAA
rating, which is not based on TVA’s excellent financial performance, but on the fact that
TVA is a federal entity: “The TVA power bond rating reflects TVA’s status as a wholly
owned corporate agency and instrumentality of the U.S. government... the fact that the
government is TVA’s only shareholder, indicates strong ‘implied support’ [that] would
afford assistance in times of difficulty.... TVA’s nuclear risk, average competitive
position, and high level of debt would make it unlikely to maintain current [AAA] status.”
These advantages are not available to IOU’s, whose investors must be paid a premium
to compensate them for the risk of financial default.

The PMAs may have even easier access to subsidized capital since they borrow
directly from Congress. The average interest rate paid by a PMA ranges from 2.7
percent for SWPA to 4.6 percent for SEPA. In contrast, long term debt held by IOUs

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7 EOP Group study.
Conference Draft

(in 1993) carried an 8.1 percent average interest rate. The rate paid by the PMAs is actually lower than the rate at which the government borrows money (6.9 percent in 1995\textsuperscript{10}). Moreover, the debt is only repaid over an extended period of 50 years, which enables the PMAs to charge even lower prices.

Some subsidies are the consequence of accounting methods that lower the costs that have to be covered through power rates. For example, the PMAs use artificially long depreciation periods.

Finally, federal power is exempt from antitrust laws, and costly FERC hydroelectric licensing procedures and receives congressional appropriations for non-power activities, the costs of which investor-owned hydro facilities must recover through sales of electricity.

TVA and BPA provide striking examples of how the incentives faced by public power producers lead to wasteful activities for which the public ultimately picks up the tab. Both entities became involved in extensive nuclear programs that ultimately failed, leaving in their wake huge debts.

TVA established a nuclear program during the 1960s and 1970s that was supposed to create the largest nuclear system in the country. Construction was started on seventeen units at seven plant sites. These projects were all plagued by management problems, safety concerns and cost overruns virtually from the start. After recent repairs and restarts, TVA now has three units in full commercial operation, with

two more running at 50 percent of capacity. The remaining units have been either shut down, canceled or are still under construction with poor prospects of ever being finished. Two units are being considered for conversion to natural gas.

All told, TVA has spent about $25 billion on nuclear construction. Of its $19.3 billion of net nuclear assets, $7.8 billion consist of construction in progress and $6.2 billion of deferred assets. Subtracting unproductive assets from TVA’s balance sheet yields a net worth of minus $8.9 billion, showing how little of a real value lies behind the AAA rating of TVA’s bonds. While investor-owned utilities also have had problems with their nuclear projects, it is TVA’s status as a federal agency, which has insulated it from adverse consequences, that enabled these highly risky investments to be made on such a large scale.

Bonneville’s nuclear saga differs only in the numbers and details. In the 1970s, the Washington Public Power Supply System (WPPSS), a consortium of publicly owned utilities, launched an ambitious nuclear program that involved BPA through “net-billing agreements”, rights to most of the generating capacity of the planned nuclear plants. These contracts made BPA responsible for most of the costs of the program. Ultimately, the program experienced difficulties, and only one of the three projected (and partly constructed) plants was put into operation. A significant portion of the costs was borne by the bondholders when the municipalities participating in the WPPSS

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defaulted on $2.5 billion of bonds in 1983. Due to the “net billing” obligations, however, BPA was left with a debt currently exceeding $7 billion.\textsuperscript{13}

Bonneville’s difficulties were not just the result of a poorly managed project. Fundamentally, they were caused by the subsidized public power sector in the Pacific Northwest, which inflated the demand for electricity and stimulated the construction of inefficient capacity additions.

Municipal and State Power

Municipal utilities have existed in the United States since as early as the 1880s. With preferential access to low-cost federal hydropower, municipal utilities were booming in the 1930s. Currently, there are about 2,000 municipally or state-owned electric utilities that serve almost 16 million customers.\textsuperscript{14} Many municipal utilities, especially those serving small towns, are merely distribution systems that buy power from federal and state, as well as investor-owned utilities. However, many of them are large entities with substantial generation facilities and thousands of employees. By far the largest municipal system is run by Los Angeles Department of Water and Power, which supplies more than 1.3 million retail customers.\textsuperscript{15} Municipal utilities sometimes pool their resources together to build larger projects or to make aggregate wholesale

\textsuperscript{13} Bonneville Power Administration 1993 Annual Report, p. 25.
power purchases. Examples of such "coalitions" include MEAG Power in Georgia, the Southern California Public Power Authority and WPPSS.

State-level involvement in the electric power business comes in two forms. The first is represented by state irrigation and water supply projects, such as the Salt River Project in Arizona, the Imperial Irrigation District California, and the Lower Colorado River Authority in Texas. The second is represented by state authorities and public power districts established during the Depression that are directly involved in generation, transmission and sometimes distribution. Examples include the New York Power Authority, which is the largest public power system measured by MWh sales (see Table V.2) and South Carolina Public Service Authority, more commonly known as Santee Cooper.

<table>
<thead>
<tr>
<th>Publicly Owned Utility</th>
<th>State</th>
<th>Sales (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New York Power Authority</td>
<td>NY</td>
<td>38,541,969</td>
</tr>
<tr>
<td>Salt River Project</td>
<td>AZ</td>
<td>22,631,138</td>
</tr>
<tr>
<td>Los Angeles Dept. of Water and Power</td>
<td>CA</td>
<td>21,765,768</td>
</tr>
<tr>
<td>Puerto Rico El. Power Authority</td>
<td>PR</td>
<td>14,983,560</td>
</tr>
<tr>
<td>South Carolina Public Service Authority</td>
<td>SC</td>
<td>14,724,518</td>
</tr>
<tr>
<td>San Antonio City Public Service</td>
<td>TX</td>
<td>13,499,928</td>
</tr>
<tr>
<td>Intermountain Power Agency</td>
<td>UT</td>
<td>12,191,294</td>
</tr>
<tr>
<td>Memphis Light, Gas &amp; Water Division</td>
<td>TN</td>
<td>12,097,393</td>
</tr>
<tr>
<td>Nebraska Public Power District</td>
<td>NE</td>
<td>12,089,417</td>
</tr>
<tr>
<td>Nashville Electric Service</td>
<td>TN</td>
<td>10,640,616</td>
</tr>
</tbody>
</table>

Municipal and federal power are interrelated and they have developed together. In Tennessee, the massive growth of TVA, in part due to the forced sale of IOU assets to TVA, created an industry structure in which TVA has a generation and transmission monopoly while most of the power is distributed by municipal utilities. Similarly, municipal utilities would not be so prevalent in Washington state without Bonneville's dominant position. During the post-war period, the market share of municipal power in the U.S. has remained virtually constant.  

Municipal utilities enjoy preferential access to federal hydropower, exemption from income and other taxes, the ability to issue tax free bonds and some regulatory exemptions. Due to these subsidies, and the fact that hydropower is by its nature relatively low cost, the price of federal power is low. The average prices charged by SEPA, SWPA and WAPA in 1993 were, respectively, 40, 55 and 41 percent below the average wholesale prices in their regions. This low priced power is not available to all citizens, but rather flows “preferentially” to those served by public (and cooperative) utilities. This simply means that federal power must first be made available to municipal, state (or cooperative) utilities. Whatever remains is available to IOU’s. In this manner, the federal government gives publicly-owned utilities a discount worth $1.4 billion. (Assuming these savings are fully passed on to the 16 million customers

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17 PMA Value to Taxpayers and Customers, EOP Group study for the Edison Electric Institute, April 1995.
ultimately served by these utilities, the average subsidy is about $87 annually per customer.)

Municipal and state utilities are exempt from paying federal, state and local income taxes as well as property and other taxes. If they were under the same tax regime as investor-owned utilities, 19 the federal government would collect an additional $1.5 billion in income taxes while state and local governments would increase their revenues by $1.2 billion. 20

Municipal and state utilities raise most of their capital through issuance of bonds that are both tax exempt and guaranteed by the local governments. Both of these factors artificially lower the cost of capital to these utilities. Low borrowing costs imply that publicly owned utilities tend to undertake at the margin investments that are riskier and less efficient than investments undertaken by companies facing the real opportunity cost of capital. Under the equity/borrowing conditions faced by IOU's (which are still artificially advantageous due to rate-of-return regulation), municipals would incur an increase in borrowing costs of more than $800 million. 21

Unlike federal entities, state and municipally owned utilities are subject to FERC hydro licensing requirements. However, Section 7 of the Federal Power Act gives a preference to states and municipalities in obtaining a license to develop and operate

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19 That is, paying the same taxes and enjoying the same tax relieves like subtracting past losses from taxable income.
hydro projects. More importantly, municipalities are not subject to antitrust requirements and to rate of return regulation as applied to IOUs in most states.

Cooperative Power

In 1931, only 10.4 percent of farms in the United States had electricity and the rate of growth of new connections was being slowed by the Depression. In response, President Roosevelt in 1935 created the Rural Electrification Administration (REA) and Congress, a year later, passed the Rural Electrification Act. Both of these actions were aimed at providing permanent federal funding in order to bring electricity into every home.

REA was simply a bank giving loans to bring new electric service to rural areas, defined as population centers under 1500 persons. Its budget was $50 million in 1937 and $40 million for the following eight years. The primary recipients of loans were rural electric cooperatives (RECs), which are non-profit businesses owned by electricity consumers, and can be divided into two groups: distribution co-ops, which operate a distribution system in the area they serve and buy power from investor-owned, federal, cooperative and other generators; and G&T coops, which operate generation and transmission facilities, usually for the benefit of smaller distribution co-ops.

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23 Only 14 states have authority to regulate municipal utility rates. Among these prevail the Northeastern states where municipal power has been traditionally unimportant. Source: NARUC Compilation of Utility Regulatory Policy 1993-94, p.45.
The rural electrification program yielded results and was politically popular. In 1944, 43 percent of farms were enjoying electric service.\textsuperscript{26} It is questionable, however, how much of this can be attributed to the REA. The boom of the late 1930s and early 1940s accelerated rural hookups by investor-owned utilities (600,000 farms were connected during 1935-39) and it is very likely that many REA-aided areas would have received electric service anyway. The federal subsidy only made it cheaper. And, despite favorable federal treatment of co-ops and municipal and state utilities, 60 percent of the population living in rural areas today receive service from investor-owned utilities.\textsuperscript{27}

Currently there are 937 rural coops serving 10.8 percent of the nation's customers and generating 5.6 percent of the nation's electricity.\textsuperscript{28} While REA was only intended to be in operation until 1946, it was reauthorized in 1944 and remains in existence today as the Rural Utilities Service—a good example of how difficult it is to eliminate a subsidy once it is in place.

The general taxpayer has paid, and continues to pay, a portion of farmers' electricity bills. The advantages enjoyed by co-ops are similar to those enjoyed by municipal utilities and consist primarily of REA low-interest loans, federal loan guarantees, preferential access to federal hydropower, exemption from most taxes, and some regulatory requirements.

\textsuperscript{26} Rural Electric Sourcebook 1990, p. 18.
\textsuperscript{27} Subsidies and Unfair Competitive Advantages Available to Publicly-Owned and Cooperative Utilities, Putnam, Hayes and Bartlett report for Edison Electric Institute, September 1994, p. ix.
Conference Draft

The 1944 amendment to the Rural Electrification Act established the interest rate on REA loans at two percent, a rate that was in effect until 1993.\textsuperscript{29} Currently, co-ops meeting hardship criteria borrow at five percent and others borrow at a rate equal to the average rate on tax-exempt municipal bonds or seven percent, whichever is lower. Loans to rural co-ops totaled $43 billion in 1994.\textsuperscript{30} If the co-ops faced the real cost of capital, they would need almost $800 million of additional revenue.\textsuperscript{31}

The low-cost federal power is a source of an additional subsidy for co-ops, amounting to $780 million.\textsuperscript{32} While co-ops pay social security taxes and in some cases even local taxes, putting them under the same tax regime as investor-owned entities would bring $1 billion to the federal budget and over $1.1 billion to state and local budgets.\textsuperscript{33}

Finally, municipal, cooperative and state utilities also have an advantage because they are unburdened by any PURPA obligations. PURPA requires IOUs, but not publicly owned and cooperative utilities, to purchase cogenerated or renewable power at state-commission set "avoided costs". These contracts now account for a significant part of stranded costs.

\textsuperscript{29} Subsidies and Unfair Competitive Advantages Available to Publicly-Owned and Cooperative Utilities, Putnam, Hayes and Bartlett report for Edison Electric Institute, September 1994, p. 25.
\textsuperscript{30} Reforming Electric Subsidies to Enhance Competition, The State Factor, Vol. 21 No. 5 1995, American Legislative Exchange Council.
Conference Draft

Public Power in the Face of Emerging Competition in the Electricity Industry

In the traditional regulated environment, the public and investor-owned power markets have to a large extent been separated from each other. A municipality producing, buying and distributing subsidized power to its residents could do so without much impact on private utilities outside its market area. This will not be the case in an environment in which suppliers are able to compete at both the wholesale and retail levels.

The benefits that public power providers enjoy in terms of exemption from taxes, subsidized borrowing costs and preferential access to federal hydropower create an artificial competitive advantage vis-a-vis private providers who do not enjoy these subsidies. Public power providers will be able to offer lower prices to consumers in a retail wheeling regime. They may also be able to use tax-free or subsidized capital to construct new generating capacity. Hence, the share of public power may increase, not because public power is truly more efficient, but simply because it enjoys a series of explicit and implicit subsidies.

The preferential legal position enjoyed by public utilities creates additional complications in a deregulated environment. Under FERC Order No.888 on nondiscriminatory open transmission access, utilities are required to open their transmission networks for wholesale transactions. FERC does not have the authority to impose the same rules on PMAs, munies and co-ops, which only are required to open their transmission networks to IOUs whose networks they want to use to have their
power wheeled out. The power that they purchase for resale, however, public entities must be given open access if they want to wheel power in. If a municipal utility owns a transmission system but either does not own generation facilities or has no interest in selling its own power at wholesale, it does not have to open its network to other utilities. But it can require open access from surrounding utilities to obtain power from wholesale markets. Hence, public power is granted the full benefits of open access to private utility systems without having to reciprocate.

A similar asymmetric treatment prevails at the retail level. For example, under the California restructuring bill passed this year, municipal utilities are required to put their transmission systems under the control of the Independent System Operator. They are not, however, required to give their customers retail access to competitors until two years after the investor-owned utilities have done so.

TVA also has been protected from competitive developments by a “fence” created by the TVA Self-Financing Act of 1959. TVA is not subject to open access requirements and, therefore, the advantages of wholesale competition are not available to municipal utilities inside its service area. TVA’s control of key transmission assets in the Southeast and, to a lesser extent, BPA’s control of transmission assets in the Pacific Northwest, may impede the smooth functioning of power markets in those parts of the country.

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34 This is called a “reciprocity provision” in the industry jargon.
35 California AB 1890, Sec. 9601, 9602.
36 It is required to provide open access on the basis of the reciprocity provision; it also may open its network voluntarily.
The development of competition in wholesale markets has stimulated the formation of municipal systems. Since competition is not yet available at the retail level, formation of a municipal system has become a way for consumers to gain access to low-cost power. Large industrial consumers are frequently the strongest supporters of these programs.

Local governments can generally form a utility by acquiring existing utility assets under their power of eminent domain. Municipal utilities always have been able to obtain relatively low-priced power at the wholesale market and their ability to do so has been increased by FERC's open access order.

During the 1980s, there were about 30 successful municipalizations. Recently, some cities have attempted to create "muni lites", that is, municipal utilities that do not own any facilities except for meters. For example, Falls Church, Virginia attempted to gain wholesale wheeling access by taking over Virginia Power's meters, leaving the operation of the distribution system to Virginia Power. The proposal eventually died when the Virginia State Corporation Commission ruled that the formation of a municipal utility requires the Commission's authorization. In another case, FERC did not authorize wheeling for the city of Palm Springs, California, which tried to become a utility by installing duplicate meters. Although these attempts have not been successful, the demand for municipalization is not going to decrease. Several years ago, for example, the Massachusetts legislature declared the Massachusetts Bay

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37 Subsidies and Unfair Competitive Advantages Available to Publicly-Owned and Cooperative Utilities, Putnam, Hayes and Bartlett report for Edison Electric Institute, September 1994, p. 27.
Conference Draft

Transportation Authority was a wholesale electric utility and thus eligible for wholesale wheeling.

The Remedy: Privatize, Equalize

The existing subsidies and preferences available to federal, state, municipal and cooperative utilities will place IOUs at an increasing disadvantage as competition becomes more prevalent. In order to level the playing field, the federal government should privatize both the PMAs and TVA. Privatization, or, at a minimum, removal of subsidies is good public policy at the state and local level as well.

While there have been several attempts to privatize the PMAs, the only accomplishment thus far has been the sale of the Alaska Power Administration to its preference customers, which is more accurately described as defederalization than privatization.

The numerous beneficiaries of subsidized federal power obviously are obstacles to its privatization. The substantial privatization that has occurred in other countries throughout the world, however can provide some useful lessons for the United States.

The plan for privatizing SEPA, SWPA and WAPA proposed by Rep. John Shadegg is based on a method pioneered in the Czech Republic. The consumers of PMA power (household, commercial and industrial) would be given warrants entitling them to purchase PMA shares at a discounted price. The recipients would be free to buy shares and keep them, or to sell the warrants directly. Since the market value of the shares would be higher than the discounted price, the warrant holders could make a
profit by selling the warrants to investment bankers or anybody else interested in acquiring PMA shares. This would serve to compensate public power consumers for any rate increases that might result from privatization.39

This approach could be used immediately for the three "easy" PMAs—SEPA, SWPA and WAPA—and with some modifications for BPA and TVA, which are more complex because of their current debt and asset structure. Privatization would make it plain that the government's nuclear programs had lost billions of dollars. Any privatization plan for BPA and TVA would need to deal with this "stranded cost" issue and take into account the claims of TVA bond holders (even though, technically, the federal government has no legal obligation to repay the bonds in the case of a TVA default). In any event, some variant of the warrant approach should be a suitable tool for enlisting consumers' support.

Municipal and state utilities should also be privatized, but this is an issue for local decision makers. State and local governments would receive substantial revenue from the sale of their electric systems and subsequently additional revenues from income and property taxes. Again, these systems could be privatized by sale to their customers, which is how New Zealand privatized its distribution companies. It is possible competitive pressures would drive prices below those charged by publicly owned subsidized utilities, making the benefits of privatization apparent.

In addition to producing power, public utilities engage in a variety of non-power activities, often paid for by electricity revenues. For example, Bonneville is deeply

39 A detailed description and discussion of such a privatization scheme can be found in Michael K. Block and Congressman John Shadegg, "Lights out on Federal Power: Privatization for the 21st Century".
involved in a salmon protection program, which costs Northwest power consumers $450 million a year; the Salt River Project and the Lower Colorado River Authority are responsible for irrigation and flood control; the Tacoma Public Utility runs a railroad system; and the Sacramento Municipal Utility District undertakes "soft energy" projects. These activities reduce the value of electric systems to potential buyers, and also create another group that fears the loss of benefits from privatization.

Whether or not public power is privatized, it should be required to compete under the same rules and conditions as other power providers. Even if the PMAs remain under federal control, their power should not be sold preferentially to some customers. Rather, it should be made available to any interested buyer in the open market. The PMAs and TVA should, like other utilities, be required to file open access tariffs with FERC. States may also need to change their legislation to apply to munies and co-ops the same rules that apply to IOUs concerning retail wheeling and regulation of distribution charges.

The federal government should end all tax advantages available to public power, including those to its own power activities. The PMA, TVA, municipal, state and cooperative utilities should be subject to the same tax provisions that apply to IOUs. Similarly, TVA and munies should not have their borrowing costs subsidized through use of tax-free bonds. Specifically, we suggest that, beginning on a date certain, no municipality or other public power entity should be permitted to issue tax free bonds to

Progress and Freedom Foundation, August 1996.

VI. THE PUBLIC UTILITY HOLDING COMPANY ACT

PUHCA was enacted during the Great Depression in order to address problems in an energy industry perceived to have "concentrate[d] control of vast utility empires in a few hands, which led to deception of investors, excessive rates for consumers, and obstruction of state utility regulation." In order to address these problems, the Act required the integration and simplification of utility holding company systems into single "integrated public-utility systems."

A holding company is any company which owns the stock of another company. PUHCA defines a utility holding company as "any company which directly or indirectly owns, controls, or holds with the power to vote, 10 per centum or more of the outstanding voting securities of a public utility." For the purposes of the Act, an "electric utility company" means any company which owns or operates facilities used for the generation, transmission or distribution of electric energy for sale, other than sale to tenants or employees of the company operating such facilities for their own use and not for resale. A "gas utility company" is generally a company that owns or operates facilities used to distribute gas at retail.

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3 Section 2(a)(7)(A) of the Act.
4 Supra, Section 2(a)(3).
5 Supra, Section 2(a)(4).
The holding company structure has always played an important role in the utility industry. In 1932, three holding companies accounted for about half of the investor-owned electric utility market. In 1935, about 80 percent of the electric and gas utility industry was controlled by holding companies. With PUHCA's enactment, more than 200 registered utility companies—a large share of the utility industry—became subject to its rules. In 1938, the 214 utility holding companies registered under PUHCA controlled 922 utilities and 1,054 non-utility subsidiaries, and often controlled other utilities through minority shareholdings.

By 1952, the process of reducing the complexity of utility cross-ownership and reducing the number holding companies was largely complete. And today, only 14 active holding companies (11 electric and 3 gas) remain registered under the Act. The 11 registered electric utility holding companies account for about 20 percent of investor-owned utility retail electricity sales. Many of the largest electric utilities and most of the gas industry are not regulated under the Act.

Yet the holding company structure is clearly valuable to utilities as they continue to organize this way despite the substantial regulations imposed by PUHCA. In fact, a number of pending mergers in the energy industry would create new registered holding companies.

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* Hawes at 222.
* See William J. Baumol and Robert D. Willig, "The Economic Case for Repeal of the Public Utility Holding Company Act of 1935," attached to Comments of Central and South West Corporation at 3 (February 6, 1995).
* Mergers currently at various stages of implementation will create four utility holding companies, three of which are electric utility holding companies. These mergers are Union Electric and CIPSPO, Inc.; Public Service Company of Colorado and Southwestern Public Service; Northern States Power and Wisconsin Energy Corporation; and a three-way merger of WPL Holdings, IEC Industries, and Interstate Power Corp.
A utility holding company subject to PUHCA is required to "register" unless it can qualify for exemption under any of five statutory exemptions. The two main exemptions are for utility operations that are predominately in a single state and holding companies that are predominately operating utilities. Collectively, these exemptions encourage utilities to operate in single states and to maintain relatively simple organizational structures.

Under PUHCA, registered holding companies require SEC approval to issue or sell securities, acquire utility or nonutility assets, sell utility assets or enter into service arrangements with sister companies.¹⁰ PUHCA also imposes rules on various intercompany transactions, record-keeping and accounts, and contracts between operating and service companies. Utilities are also required to file both routine and transaction-specific reports with the SEC.

Perhaps the most important aspect of PUHCA regulation is the "integration requirement."¹¹ PUHCA places a virtual ban on the acquisition of geographically distant utility assets through the holding company form. The effect of this restriction is to keep both registered and unregistered utility holding companies largely confined to one geographic area.¹² The Energy Policy Act of 1992¹³ weakened this restriction, by permitting investments by registered and exempt holding companies in foreign utility companies and exempt wholesale generators (EWG's), "wherever located." PUHCA continues to affect the acquisition of other systems, however, and while the integration

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¹⁰ SEC Report at 8-11
¹¹ See Section 2(a)(29) of the Act.
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requirement does not apply to EWG's, other provisions of PUHCA do. For example, when acquiring an EWG, a registered holding company is limited in the amount it can invest.

The integration requirement is subject to interpretation by the SEC, which appears to have loosened its interpretation of the requirement over time. For example, the SEC recently approved a merger where the utilities in question were part of the same power pool rather than actually contiguous.14 The SEC could, however, change course at any time.

Finally, PUHCA regulates the degree to which a registered holding company can acquire non-utility assets. Thus, the Act restricts diversification by registered holding companies into non-utility businesses as well as into other utility businesses.

PUHCA And State Restructuring Plans

Most of the states currently are studying options for restructuring their electric energy markets. In a number of states—including California, Massachusetts, New Hampshire, New York, Pennsylvania and Rhode Island—the state public utility commissions or legislatures have adopted, or are close to adopting, specific restructuring plans. Each of these states is proposing to allow retail customers to buy power directly from generators or other alternative suppliers. In such transactions, the traditional

14 See Unitel case.
franchise utility would merely transmit and distribute power. The benefits to consumers of such market arrangements are obvious. Competition between generators will lead to lower prices.

PUHCA interferes with state-level restructuring efforts in two ways. First, it makes it difficult for states to implement asset divestiture and unbundling proposals. Second, it will diminish the entry into retail markets of other power suppliers that is necessary for restructuring proposals to produce maximum benefits for consumers.

Unbundling (Charts 1 and 2):

An important aspect of a number of state proposals is divestiture of generation assets, or the unbundling of utility assets into a generating company (Genco), transmission company (Transco) and distribution company (Disco). In California, for example, Southern California Edison and Pacific Gas & Electric have been ordered to divest themselves of at least 50 percent of their fossil generation capacity. The purpose of these proposals is to reduce the potential for market power and cross-subsidization on the part of a vertically integrated utility, and to facilitate regulation of monopoly transmission and distribution services. Proposals differ as to whether the divested Gencos, Transcos and Discos could remain affiliated within a holding company structure.

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15 Other examples of divestiture proposals include the restructuring proposals submitted by the Division of Energy Resources, Commonwealth Electric and Massachusetts Electric in Massachusetts, Public Service Commission and Niagara Mohawk Company in New York, and the Rhode Island restructuring act.
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In some cases, PUHCA makes adoption of corporate unbundling almost impossible. Unbundling an existing non-holding utility company into legally distinct Genco, Transco and Disco would create a new registered or exempt holding company. The large non-holding company utilities that operate in more than one state would be the primary candidates for becoming registered holding companies if one of the states in which they operate was to issue a corporate unbundling order. As Chart 1 shows,
Chart 1: State Public Utility Commission Orders Corporate into Genco, Transco and Disco within a Holding Company

With PUHCA

- **Commission Order**
  - Utility becomes a holding company with Genco, Transco and Disco subsidiaries
  - The utility must comply with PUHCA as a holding company

  - **SEC exemption test**
    - yes: Utility becomes an EHC
    - no: Utility becomes a RHC

  - Utility challenges the State Commission order in court
    - **Court rules in favor of the utility**
      - yes: Restructuring is suspended
      - no: SEC integration requirement compliance test
        - no: Order to divest non-integrated assets
          - yes: SEC test on compliance with non-utility business ownership limitation
            - no: Order to divest non-retainable non-utility businesses
              - yes: The RHC reports to SEC on its activities. Asset acquisitions, stock issuances and affiliate transactions are subject to SEC approval
        - yes: Order to divest non-integrated assets
this would impose significant costs and procedural delays on existing utilities. Some of the most significant costs include possible spin-offs of non-integrated or non-retenable non-utility assets.

Due to these potential costs, affected utilities are likely to raise legal challenges, thus frustrating or at least delaying restructuring efforts. Even if events never reached this stage, utilities could point to this troublesome aspect of PUHCA in regulatory proceedings. This might have a "chilling" effect on state commissions, which may respond by avoiding corporate unbundling proposals, even though, in the absence of PUHCA, such proposals would be a beneficial part of a competitive restructuring package.

If PUHCA did not exist, corporate unbundling would be much more straightforward, as the contrast between Charts 1 and 2 demonstrates.

Chart 2: State Public Utility Commission Orders Corporate Unbundling into Genco, Transco and Disco within a Holding Company Structure

Without PUHCA

[Diagram showing the process of a commission order leading to the utility becoming a holding company with Genco, Transco and Disco subsidiaries]
Barriers to Retail Entry (Charts 3-6)

A key condition for successful state restructuring plans is free entry into the energy market. Restrictions either on building new, more efficient generation plants or on entrants buying existing generation capacity have an unambiguous impact: diminished competition in a deregulated environment.

PUHCA is a significant barrier to entry in a retail wheeling environment, and it will decrease participation by some of America's most efficient firms in state competitive restructuring efforts. The Act restricts the ability of registered holding companies, exempt holding companies, non-holding companies, and non-utility companies to enter newly restructured markets.

The geographic integration requirement of PUHCA prevents registered holding companies and their affiliates from buying or building generation capacity to compete in a geographically separate retail market. An acquisition that fails to satisfy the SEC integration requirement compliance test cannot be completed, as is shown in Chart 3. For example, the New England Electric System cannot own a generation plant in California that directly competes in the California retail market, even though there is no economic reason why it should not be allowed to do so.

Also, as Chart 3 shows, even when an acquisition is consistent with PUHCA's geographic integration requirements, the registered holding company still needs approval from the SEC on the acquisition and its financing. The SEC approval process is costly, uncertain and time consuming. Even if approval is eventually forthcoming, the delay may be a dealbreaker, and the asset may not be obtained by the most efficient operator.
Exempt holding companies also may face SEC jurisdiction if they attempt to enter a newly restructured retail market, especially if such an entry would threaten their exemption status. The prospect of becoming a registered holding company may well deter an exempt holding company from pursuing transactions in out-of-state restructured markets. Even if willing to carry this burden, the SEC approval or procedural delay may be a dealbreaker, as is illustrated in Chart 4.
Chart 3: Acquiring* Retail Generation Plant by Registered Holding Company

With PUHCA

- Plan to acquire retail generation
- DOJ, FERC review, if necessary
- Request for SEC approval
  - SEC integration requirement compliance test
    - no → DEALBREAKER
    - yes → SEC approval of acquisition and financing
      - yes → SEC approval was timely
        - yes → Acquisition of plant
        - no → DEALBREAKER
      - no → DEALBREAKER

* Either purchasing or building
Chart 4: Acquiring Retail Generation Plant by Out-of-State Exempt Holding Company

With PUHCA

- Plan to acquire retail generation
- DOJ, FERC review, if necessary

- Company would lose exemption because of transaction
  - no: Acquisition of plant
  - yes: Decision on whether to become a RHC
    - yes: Request for SEC approval
      - yes: SEC approval of acquisition and financing
        - yes: The company becomes a RHC, subject to all PUHCA requirements, including integration and non-utility business requirements
        - no: DEALBREAKER
      - no: DEALBREAKER
    - no: DEALBREAKER

* Either purchasing or building
Retail transactions across state boundaries that do not involve the acquisition of
generation might also create problems for exempt companies. For example,
California’s consumers might benefit from buying power directly from Arizona Public
Service, which is a subsidiary of Pinnacle West, an exempt holding company because
its operations are limited to a single state. If Arizona Public Service bought a
distribution company in California and sold a significant amount in that market, its
operations would no longer be limited to a single state and it might lose its exemption.
As a result, Arizona Public Service might choose not to compete in the California retail
market.

Finally, the exempt status of exempt wholesale generators (EWGs) may diminish
their importance as potential competitors. EWGs represent an easy source of entry into
the retail generation markets. By selling at retail, however, an EWG’s operations would
no longer be limited to wholesale level, and it would lose its exemption from PUHCA.
The costs of losing the exemption are likely to keep the EWGs off the retail market.

PUHCA also will make it more difficult for utility companies that are not already
holding companies to enter new retail markets. Such companies may, for financing and
other reasons, prefer to create a new corporate entity when acquiring a generation
plant used to make retail sales. As Chart 5 shows, entering a retail market in this
manner creates a maze of PUHCA-related procedures and requirements that may
eventually result in ordered divestitures of substantial assets from the entering entity.
This possibility, and the administrative costs and other restrictions of PUHCA, are likely
to cause such companies to avoid these transactions. In particular, any transaction that
entails becoming subject to PUHCA is very likely to deter companies that are not already holding companies.

Any corporate entity that owns retail generation becomes an “electric utility company” under PUHCA. A parent of such an entity (unless able to qualify for an exemption) must register and thereby become subject to all the requirements of PUHCA, including the geographic integration and ownership of non-utility assets requirements. Non-holding companies that are not already in the electricity business may bypass PUHCA when acquiring a retail generation plant by not using a holding company structure. In that case, however, the company would, as shown in Chart 6, become an “electric utility company” under PUHCA. Future activities, whether in the power industry or elsewhere, that would entail creating a holding company would make such a company subject to full PUHCA requirements, unless an exemption could be found. Such a threat is likely to deter non-power companies from entering the retail generation business.

Thus far, state restructuring proposals typically have not mandated the use of wholesale power pools, which provide another possible framework for competition. The exceptions are California, where initially all utility power must be traded through a pool,
Chart 5: Acquiring Retail Generation Plant by Non-Holding Electric Company

With PUHCA

1. Plan to acquire retail generation
   - DOJ, FERC Review, if necessary
     - Decision on whether to create subsidiary
       - yes
         - Proposal to form subsidiary
           - SEC exemption test
             - yes
               - Formation of subsidiary, utility becomes an EHC
               - Acquisition of plant by the subsidiary
             - no
               - Order to divest non-retainable non-utility businesses
               - Decision on whether to proceed
                 - yes
                   - SEC approval of acquisition and financing
                     - yes
                       - SEC test on compliance with non-utility business ownership limitation
                         - yes
                           - Order to divest non-integrated assets
                           - Decision on whether to proceed
                             - yes
                               - SEC approval was timely
                                 - yes
                                   - Acquisition of plant by the subsidiary
                                 - no
                                   - DEALBREAKER
                             - no
                               - DEALBREAKER
                           - no
                             - DEALBREAKER
                         - no
                           - DEALBREAKER
                       - no
                         - DEALBREAKER
                   - no
                     - SEC test on compliance with non-utility business ownership limitation
                       - yes
                         - Order to divest non-integrated assets
                         - Decision on whether to proceed
                           - no
                             - DEALBREAKER
                         - no
                           - DEALBREAKER
                       - no
                         - DEALBREAKER
         - no
           - Acquisition of plant by the utility
   - no
     - Decision on whether to become a RHC
       - yes
         - DEALBREAKER
       - no
         - SEC integration requirement compliance test
           - yes
             - Order to divest non-integrated assets
             - Decision on whether to proceed
               - yes
                 - SEC approval was timely
                   - yes
                     - Acquisition of plant by the subsidiary
                   - no
                     - DEALBREAKER
               - no
                 - DEALBREAKER
           - no
             - DEALBREAKER

* Either purchasing or building
** Assuming that the state commission does not require separate corporate structure for owning generation
Chart 6: Acquiring* Retail Generation by Non-Utility

With PUHCA

Plan to acquire retail generation

yes
Decision on whether to create subsidiary**

no

Formation of subsidiary

DOJ, FERC review, if necessary

DOJ, FERC review, if necessary

Acquisition of plant by subsidiary

The company becomes an electric utility

Company becomes subject to PUHCA, must comply with PUHCA as a holding company

Any future activity consisting of creating a holding company makes the company subject to PUHCA

SEC exemption test

Company becomes a RHC

SEC test on compliance with non-utility business ownership limitation

The EHC reports to SEC on its activities

Order to divest non-retainable non-utility businesses

The RHC reports to SEC on its activities; asset acquisitions, stock issuances and affiliate transactions are subject to SEC approval

Decision on whether to proceed

yes
Dealbreaker; the company sells the plant

no

* E. ir. purchasing or building

** Assuming that the state commission does not require separate corporate structure for owning generation
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and New York, where the pool structure is required to be in place before retail wheeling is implemented in 1998. Although a pool structure eliminates some of the problems discussed above, because generators selling into the pool are considered wholesale and therefore exempt, some PUHCA-induced-restrictions remain. In particular, the ability of registered holding companies to participate by owning EWGs outside their integrated service territories would still be limited by SEC investment rules for such companies (see Chart 7).
Chart 7  Acquiring\* Exempt Wholesale Generator by Registered Holding Company

With PUHCA

- Plan to acquire an EWG
- DOI, FERC review, if necessary
- Request for SEC approval of financing

- no

  SEC approval of financing

  yes

  DEALBREAKER

  no

  SEC approval was timely

  yes

  Acquisition of an EWG

* Either purchasing or building
Without PUHCA, as Chart 8 shows, the process of acquiring utility assets will be greatly simplified and much more attractive to a large number of potential entrants.

Paradoxically, even though PUHCA directly regulates registered holding companies, the high costs of becoming a registered holding company prevents retail entry by those companies that actually do not fall under its jurisdiction. (Compare Charts 5 and 6 with Chart 3).

Thus, PUHCA is viewed as serving consumers’ interests by limiting market power through merger control, in fact the Act increases market power by raising barriers to entry into newly restructured retail markets. The repeal of PUHCA is necessary to provide electricity consumers the greatest benefits of electricity competition.
Chart 8: Acquiring* Utility Assets by Any Entity (Non-Holding Utility, Utility Holding Company, Non-Utility Company)

Without PUHCA

Plan to acquire utility assets

yes

Decision on whether to create subsidiary**

no

Formation of subsidiary

DOJ, FERC review, if necessary

Acquisition of utility assets by subsidiary

DOJ, FERC review, if necessary

Acquisition of utility assets

* Either purchasing or building
** Assuming that the state commission does not require separate corporate structure for owning generation

Additional Barriers to Efficiency

Quite apart from the direct impact PUHCA will have on state competitive restructuring programs, the Act imposes substantial social costs on electricity and gas customers, stockholders and the public at large by erecting barriers to efficiency and by imposing significant administrative, financing and transactions costs.
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PUHCA restricts the movement of registered holding companies into markets that are not geographically connected or capable of such interconnection. The SEC has recognized that these requirements are restrictive, and while it appears that the SEC is relaxing its interpretation of this section somewhat, such mergers are nevertheless subject to regulatory scrutiny by the SEC as well as by FERC.¹⁶

The potential benefits lost because of the restrictions on non-contiguous utility integration include: a more efficient mix of generating facilities through better coordination;¹⁷ savings due to a more efficient scale of overhead activities;¹⁸ and, savings due to more efficient matching of load diversity.¹⁹ The present value of the total savings from lifting restrictions on non-contiguous utility mergers is estimated at approximately $2 billion— and this does not include the "cost" of the integration requirement imposed on consumers of states where competitive restructuring is underway.²⁰

In addition, PUHCA directly and indirectly restricts registered holding companies from engaging in non-utility activities.²¹ The "ten-percent rule" directly restricts a registered holding company to no more than 10-percent ownership of a subsidiary venture before that venture is subject to the requirements of PUHCA. Furthermore, the "functional-relationship test" combined with the "50-percent rule" essentially requires

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¹⁶ Moreover, it appears that the FERC is subjecting all mergers to greater scrutiny. See e.g. the Washington Water Power and Sierra Pacific merger.
¹⁷ Particularly those not achieved through the use of power pools, i.e. those that are geographically distant.
¹⁸ Paul R. Carpenter and Frank C. Graves, "Estimating the Social Costs of PUHCA Regulation", attached to comments of Central and South West Corp. (February 6, 1995) at 12.
¹⁹ This is likely to be important in the context of PUHCA repeal as geographically distant regions typically have different peak times. This allows the firm to more efficiently use its generating resources.
²⁰ Carpenter and Graves at 19.
²¹ Section 9(a)(1) of the Act generally requires Commission approval, by order upon application, before a
that the business a registered holding company does in a "functionally related" area outside the firm cannot exceed what the company does inside.\textsuperscript{22} Although the SEC has begun recently to make exceptions to the 50-percent rule, these rules still constitute significant direct restrictions on non-utility activities.

Indirectly, the Act creates a "chilling effect" on non-utility activities by requiring SEC oversight of these businesses.\textsuperscript{23} The fact that firms must publicly disclose the details of these businesses, and incur compliance costs, imposes a burden that affects exempt holding companies and non-utilities as well as registered holding companies.\textsuperscript{24}

Utilities have a comparative advantage in many non-utility activities but are prevented from engaging in them due to PUHCA.\textsuperscript{25} The costs associated with limits on diversification were somewhat mitigated by enactment of the Telecommunications Act of 1996, which permits registered holding companies to enter the telecommunications business.\textsuperscript{26} This legislation will produce large benefits because the electric utility industry already has laid 10,000 miles of fiber optic cable for its own data transmission and other purposes. This cable capacity has gone underutilized because of PUHCA and now may be made available for other purposes.

Many industry observers anticipate that electric utilities will find significant efficiencies in having homes wired for improved energy-use metering and applications such as "real time pricing" of electricity. In the event this takes place, utilities obviously

\textsuperscript{22} Carpenter and Graves at 4.
\textsuperscript{23} Carpenter and Graves at 4.
\textsuperscript{24} Such compliance costs also reduce the competitiveness of these businesses.
\textsuperscript{25} See Carpenter and Graves at 7 for a list.
\textsuperscript{26} The Telecommunication Act, however, keeps some reporting burdens on registered holding companies and restricts their affiliates from financing the acquisition of telecommunication companies.
will be in a good position to utilize the same wires to offer telecommunications services at very competitive prices. This is now permissible, but other potential benefits of diversification are not currently feasible. For example, while the 1996 Act permits electric utilities to diversify into telecommunications, the reverse is not true. Telecommunications companies cannot diversify into the retail electricity business without being subject to the requirements of PUHCA. And, the Act continues to restrict entrance by electric utilities into non-telecommunications businesses.

Given that there are important complementarities between a number of industries and electric utilities, it is likely that many firms would find it profitable to enter utility markets, thus bringing additional capital and expertise. In general, PUHCA limits the possibility of innovative and efficient industrial companies acquiring electric utilities and applying the lessons learned in competitive industries to their regulated firms.

Restrictions on Financing, Affiliate Transactions and Administrative Costs

As discussed previously, the regulatory costs imposed by PUHCA to a non-utility of acquiring a utility are prohibitive. Such a company, under the Act, could be required to become a registered holding company. Registered holding companies need SEC approval to issue or sell securities, acquire utility or nonutility assets, sell utility assets or enter into service arrangements with sister companies. This clearly makes it nearly impossible for a non-utility to consider acquiring utility assets.

There are, moreover, substantial costs routinely associated with PUHCA's regulation of utility financing. Since companies must obtain SEC approval for numerous
activities, they are often significantly delayed in responding to market opportunities. The benefits of optimal financial arrangements are slow in coming, and therefore may be foregone. As discussed below, state utility commissions also regulate these decisions, and this local regulation is likely to be better able to assess local needs.

Finally, each registered holding company annually must file a number of routine reports with the SEC to meet the requirements of PUHCA. The cost of filing these required forms has been estimated at $6 million annually (or more than $50 million on a present value basis).\textsuperscript{27} In addition to these routine filings, utilities must file applications with the SEC to obtain approval for various transactions, and any company in a registered holding company system must seek SEC approval any time it undertakes a non-routine activity which falls under the purview of PUHCA. The costs of these requirements have been estimated at more than $10 million annually (or more than $100 million on a present value basis).\textsuperscript{28} Thus, total annual administrative costs are estimated at $16 million annually, or approximately $150 million on a present value basis. These are costs that consumers eventually pay through higher rates for gas and electricity.

Regulatory Efficiency

Although competition at the retail level for electricity has just started to emerge, there has, in recent years, been a significant increase in wholesale electricity

\textsuperscript{27} Carpenter and Graves at 21.
\textsuperscript{28} Supra.
competition. In the gas industry, competition has increased at both the wholesale and retail levels.

Even in the absence of retail competition, this change in market structure reduces the need for PUHCA regulation. The price information from an active wholesale market is a major aid to state regulators and hence they are able to more easily judge the “reasonableness” of a local utility’s rate requests. Information generated from a competitive wholesale market is a high-powered substitute for the purported informational benefits of PUHCA regulation.

The major purpose of public utility rate regulation is to insure that rates are reasonable relative to costs. The avoidance of unauthorized cross-subsidies is particularly important for multi-product utilities. PUHCA was intended “to provide a mechanism to create conditions under which effective federal and state regulation will be possible.” It is, therefore, ironic that the Act discourages the holding company structure, which is conducive to efficient regulation.

Firms with discrete product lines can organize either through the divisional structure (examples are PacifiCorp and UtiliCorp) or as holding companies in which the divisions are separate corporate entities. The holding company structure facilitates regulation because it makes it more straightforward for both the regulator and the regulatee to allocate costs. Costs are more easily traceable to the individual products and cross-subsidies are easier to discern. It is for this reason that firms in regulated industries frequently are required to provide certain product lines through separate subsidiaries or affiliates (for an example, see section 272 of the Telecommunications
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Act of 1996, which requires Bell operating companies to provide certain services through separate affiliates).

The requirements of PUHCA make organizing as a holding company costly, whatever its other advantages. If PUHCA were repealed, it is likely that more firms would organize as holding companies, thereby improving the regulatory process.

PUHCA is Redundant

As the SEC has recognized, the regulation of utilities has become vastly more sophisticated at both the federal and state levels in the years since PUHCA was enacted. The pervasiveness of other regulatory programs makes the PUHCA requirements duplicative and unnecessary.

State Regulation

One of the intentions of PUHCA was to facilitate the regulation of electric utilities on the state level through simplification and data availability. Absent any of the PUHCA provisions, state regulators have expanded their authority over both electric and gas utilities and now have all the authority needed to protect consumers from unreasonable

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SEC Report at 11.
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rates. Most states also regulate securities issuances, acquisition and diversification activities and prescribe uniform systems of accounts for regulatory purposes.

All state commissions have the authority to regulate retail rates of investor-owned utilities and to demand justification before adopting any rate changes. In this connection, states have the authority to access out-of-state information that affects an in-state utility. The great majority of state commissions also have the authority to investigate rates, approve mergers, and investigate contracts and agreements between utilities and their affiliated non-utilities. Many commissions have authority to regulate utility entry into non-utility activities. Most states lacked the authority to review these activities when PUHCA was passed in 1935.

Importantly, any activity which affects rates (as all important activities invariably do) is under the control of state regulators. Thus, even if a state commission is not directly granted the authority to review a particular utility transaction, it is able to review it and take remedial action de facto through powers of rate review. Similarly, even if a commission did not have express approval power over mergers or consolidations –

30 SEC Report at 32-34.
31 For example according to the survey in Edison Electric Institute, August 1994, State Regulation of Utility Diversification. 337 Public Utility Commissions in all states and District of Columbia have authority over forming a holding company, and 30 of them have authority over setting up a subsidiary.
33 SEC Report, Appendix A
34 Edison Electric Institute, August 1994. State Regulation of Utility Diversification
35 Baumol and Willig at 9.
36 SEC Report
37 There are, however, questions about the effects of SEC orders on the ability of the FERC and state regulators to exercise their authority. See e.g. Ohio Power Co. v. FERC, 954 F.2nd 779 (D.C. Cir.), cert. denied, 113 S. Ct. 483 (1992). However, many in Congress have expressed a willingness to remedy this effect. Indeed, the Telecommunications Act of 1996 included a provision nullifying the effect of the Ohio Power case for purposes of reviewing the reasonableness of a public utility seeking to recover in rates the costs of purchasing certain telecommunications services.
although most of them do – the commission could nevertheless control these transactions by reviewing their effects on rates and potentially disallowing cost recovery in the next rate hearing. Finally, in the limited number of cases where a commission does not have full access to all of a utility affiliate’s books and records, it can simply refuse to grant a rate increase if its requests for data are not met.

Federal Regulation

FERC is responsible for regulating rates for the interstate wholesale electricity and natural gas markets. As part of its regulatory functions, FERC collects detailed financial information and has established uniform systems of accounts to which regulated utilities must adhere.

FERC also has the authority to review, in advance, electric utility mergers and securities issuances, and has oversight over numerous utility transactions, including mergers, property dispositions, the acquisition and issuance of securities, and affiliate transactions. Finally, FERC has authority to scrutinize the books and records of a utility, and of a person who controls such a utility.

38 SEC Report, Appendix A
39 States almost universally allow their PUC's to investigate the details of a utility's transactions with its affiliates. See Edison Electric Institute, State Regulation of Utility Diversification.
41 Baumol and Willig at 5.
43 Federal Power Act section 301(c), 16 U.S.C. § 825(c). Chair Moler has, however, testified that the FERC would need additional statutory authority in this regard if PUHCA were repealed. 1995 Hearings before the House Subcommittees on Energy and Power, and Telecommunicationsand Finance.
With respect to the issue of access to books and records, utilities generally have the burden of proof in rate proceedings. Therefore, as a practical matter, even when a state commission does not have independent access to the books and records of a utility affiliate, the utility will be required to provide such records to the extent that they relate to the recovery of costs. Similarly, the issue of the reasonableness of affiliate transactions can be addressed by FERC and the states through their normal ratemaking authorities.

At the time PUHCA was enacted, public utilities were exempt from the federal antitrust laws. Now, not only do FERC and the SEC examine the same aspects of proposed mergers, but the Antitrust Division of the Department of Justice does as well, in order to deter mergers that are detrimental to consumers' interests. Thus there would still be redundancy in utility merger oversight even if PUHCA were repealed.

Financial Disclosure

As noted, a major goal of PUHCA was to standardize accounts and increase financial disclosure. Today, registered holding companies are subject to the same securities laws which are applicable to all publicly held companies. Repeal of PUHCA would not affect these laws in any way.

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45 SEC Report at 140-141.
46 Harvard study at 11.
47 Supra.
Moreover, the market itself "demands a level of disclosure unheard of in the days when PUHCA was passed into law" for any company that wants to attract outside capital. Any company wishing to obtain financing through organized securities markets must meet stringent standards of disclosure and uniformity, independent of the requirements of securities laws. Because of the tremendous benefits of the securities markets, there is an extraordinary incentive to meet the necessary standards. The growth of intermediaries between firms and individual investors, such as mutual and pension funds, ensures that firms are subject to a high level of financial scrutiny. Expert rating agencies, such as Duff and Phelps, Moody's, and Standard and Poor's, provide an elevated level of scrutiny.

The institutions of the accounting profession also have responded to the demands for better information. For example, the Financial Accounting Standards Board (FASB) has become increasingly important in establishing uniform accounting standards which must be used by all accountants who are members of the American Institute of Certified Public Accountants (AICPA). All financial statements certified by a member of the AICPA must follow rules established by FASB. The stricter accounting standards envisioned by the framers of PUHCA for the utility industry have thus been incorporated by the accounting profession and are now widely enforced by it. Any utility wishing to enjoy the benefits of having audited financial statements must meet these standards.

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44 Baumol and Willig at 7.
CONCLUSION

PUHCA was enacted under vastly different circumstances than exist today. In the last 60 years, the electric and gas utility industries have undergone substantial changes. Whatever the merits of PUHCA in 1935, the case for repealing it now is strong.

As the states try to move toward a more competitive environment, PUHCA stands in their way. If unchanged, PUHCA will be an even more significant impediment to the competitive restructuring of the electric utility industry in the future. For the gas industry, which has to a large extent already been restructured, the PUHCA restrictions may be even more burdensome.

Given the existing regulatory protections, the increasingly competitive electricity and gas environment, and the desire on the part of many states to move away from the old vertically integrated monopoly structures, the case for repealing PUHCA seems compelling. The SEC has been recommending PUHCA repeal, albeit in slightly different forms, for more than a decade.⁴⁹ It seems time for the Congress to act.

⁴⁹ See Statement of the U. S. Securities and Exchange Commission Concerning Proposals to Amend or Repeal the Public Utility Holding Act of 1935 (June 2, 1982).
VII. PURPA

The Public Utility Regulatory Policies Act of 1978 (PURPA) is a legacy of the energy policy of the late 1970s, which attempted to substitute the government's fuel-choice and energy conservation judgments for those of the marketplace. The dramatic run up in oil prices—by over 230 percent between 1970 and 1980—was viewed as a threat to both national security and macroeconomic stability. (See Table VII.1). As a result, the government promulgated a number of conservation measures, the most prominent of which was PURPA.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude oil</td>
<td>155.7</td>
<td>268.7</td>
<td>519.1</td>
<td>439.9</td>
<td>304.8</td>
</tr>
<tr>
<td>Natural gas</td>
<td>43.8</td>
<td>81.7</td>
<td>202.0</td>
<td>239.1</td>
<td>136.5</td>
</tr>
<tr>
<td>Anthracite coal</td>
<td>138.6</td>
<td>303.9</td>
<td>259.3</td>
<td>216.3</td>
<td>154.0</td>
</tr>
</tbody>
</table>

Table VII.1. Fossil Fuel Prices in Constant (1987) Dollars (Cents per BTU)


Enacted in 1978, PURPA was intended to conserve fossil fuels by stimulating the production of electricity from renewable sources and increasing the efficiency of electricity use. This objective was accomplished by a policy that favored (and continues to favor) renewable-resource generation and cogeneration (the production of electricity as a byproduct of other industrial processes).

While PURPA has helped to stimulate the development of a non-utility generation sector, it has saddled some utilities with substantial contractual obligations for electricity supply that are not cost-effective, even in today's market, and clearly will
not be viable in a competitive market place. These noncompetitive PURPA contracts constitute a significant percentage of utilities' stranded costs, and are an impediment to the development of competitive electricity markets.

PURPA requires utilities to purchase power from "qualifying facilities" ("QFs") at the utility's avoided cost of producing power. QFs consist of small power producers (SPPs) using renewable resources and cogenerators. Partially as a result of PURPA, non-utility generation, which includes independent power producers (IPPs) as well as QFs, increased by 275 percent during the period 1978-1992.\(^1\) The non-utility sector now accounts for eight percent of total U.S. generating capacity.\(^2\)

PURPA is an excellent example of a regulatory program that, while sounding reasonable on its face, has led to serious adverse consequences. In an unregulated market, a cost-minimizing utility would purchase outside power when doing so is cheaper than its own generation. There would, therefore, be no need for PURPA-style regulation.

In a regulated market, utilities may have strategic reasons not to purchase outside power (even if it is less expensive), since doing so may constitute a threat to their monopoly position. Therefore, requiring a utility to purchase power from QFs at the utility's avoided cost sounds like a policy that would simply simulate an efficient market and would lower prices to consumers. This has not, however, been how the statute has been implemented.


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Under PURPA, states have promoted QF electricity by adopting methodologies that yielded high avoided cost estimates and required utilities to purchase QF power under unfavorable conditions:

- In the early and mid-1980s, forecasters based avoided cost estimates on the high fuel prices prevailing at the time and failed to predict the dramatic declines in fuel prices that would occur, partially as a result of deregulation of oil prices and the market for natural gas. Oil prices in 1995 were $14.62/bbl., much lower than in the early 1980's. Natural gas prices in 1995 were $1.59/1000cu.ft., the lowest in 15 years. (Note that these numbers are in nominal dollars.) (see Table VII.2).

<table>
<thead>
<tr>
<th>Year</th>
<th>Crude Oil ($/bbl)</th>
<th>Natural Gas ($/1000cu.ft.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1970</td>
<td>3.18</td>
<td>0.17</td>
</tr>
<tr>
<td>1975</td>
<td>7.67</td>
<td>0.44</td>
</tr>
<tr>
<td>1980</td>
<td>21.59</td>
<td>1.59</td>
</tr>
<tr>
<td>1985</td>
<td>24.09</td>
<td>2.51</td>
</tr>
<tr>
<td>1986</td>
<td>12.51</td>
<td>1.94</td>
</tr>
<tr>
<td>1990</td>
<td>20.53</td>
<td>1.71</td>
</tr>
<tr>
<td>1995</td>
<td>14.52</td>
<td>1.59</td>
</tr>
</tbody>
</table>

• These high fuel prices were locked in by long-term contracts of 20 years or more, providing no flexibility or incentives (on the part of QFs) to renegotiate as conditions changed.

• Through "standard offer" contracts, utilities have been required to purchase power at preset price and other conditions, regardless of the utility’s need for the power. Although FERC promulgated this requirement only for independent generators with capacity under 100kW, some states mandated standard offer contracts for larger generators.

• Because cogenerators are only required to use five percent of the power they produce, utilities have been put in the position of purchasing high-cost power from the cogenerator and then reselling power to the same firm at lower prices.

• The treatment of capacity costs in several states resulted in an overestimate of avoided costs.

• Some states front-loaded contracts to require payments above avoided cost during the first 10-15 years of the contract.

• Finally, some states simply required utilities to enter into contracts that were intentionally above avoided cost. For example, New York enacted a statute that placed a six cent per kWh price floor on QF contracts.

Because states have had substantial discretion in the implementation of PURPA, its impact has been uneven. Table VII.3 shows in descending order the proportion of electricity capacity and generation, respectively, accounted for by QFs in each state. QF's share of generation, for example, ranges from a high of 40 percent in Hawaii to
virtually zero in South Dakota. (The proportions for Rhode Island are distorted by the fact that most of the electricity consumed there comes from outside the state.) Thus, while the federal government is clearly responsible for establishing the basic PURPA framework, the majority of states were able to implement the Act in a way that did not burden their utilities and consumers.

Table VII.3. Share of Non-Utility Generators’ Installed Capacity and Generation in the Descending Order by State

<table>
<thead>
<tr>
<th>Share of NUG Capacity</th>
<th>State</th>
<th>Share of NUG Generation</th>
<th>State</th>
</tr>
</thead>
<tbody>
<tr>
<td>40.3%</td>
<td>Rhode Island</td>
<td>89.5%</td>
<td>Rhode Island</td>
</tr>
<tr>
<td>32.7%</td>
<td>Hawaii</td>
<td>40.5%</td>
<td>Hawaii</td>
</tr>
<tr>
<td>32.2%</td>
<td>Maine</td>
<td>37.7%</td>
<td>Alaska</td>
</tr>
<tr>
<td>26.9%</td>
<td>Alaska</td>
<td>36.5%</td>
<td>Maine</td>
</tr>
<tr>
<td>20.0%</td>
<td>California</td>
<td>35.1%</td>
<td>New Jersey</td>
</tr>
<tr>
<td>18.2%</td>
<td>New Jersey</td>
<td>32.7%</td>
<td>California</td>
</tr>
<tr>
<td>16.9%</td>
<td>Idaho</td>
<td>26.9%</td>
<td>Massachusetts</td>
</tr>
<tr>
<td>14.6%</td>
<td>Massachusetts</td>
<td>21.6%</td>
<td>Louisiana</td>
</tr>
<tr>
<td>14.3%</td>
<td>Virginia</td>
<td>21.0%</td>
<td>Virginia</td>
</tr>
<tr>
<td>12.7%</td>
<td>New York</td>
<td>18.1%</td>
<td>New York</td>
</tr>
<tr>
<td>12.4%</td>
<td>Louisiana</td>
<td>17.5%</td>
<td>Texas</td>
</tr>
<tr>
<td>11.0%</td>
<td>Texas</td>
<td>17.4%</td>
<td>Idaho</td>
</tr>
<tr>
<td>10.8%</td>
<td>Nevada</td>
<td>15.7%</td>
<td>Michigan</td>
</tr>
<tr>
<td>10.3%</td>
<td>New Hampshire</td>
<td>15.2%</td>
<td>Nevada</td>
</tr>
<tr>
<td>9.9%</td>
<td>Michigan</td>
<td>13.4%</td>
<td>Connect.</td>
</tr>
<tr>
<td>9.4%</td>
<td>Connecticut</td>
<td>12.2%</td>
<td>New Hampshire</td>
</tr>
<tr>
<td>8.5%</td>
<td>Colorado</td>
<td>10.2%</td>
<td>Florida</td>
</tr>
<tr>
<td>6.6%</td>
<td>Florida</td>
<td>9.7%</td>
<td>Mississippi</td>
</tr>
<tr>
<td>6.5%</td>
<td>North Carolina</td>
<td>9.6%</td>
<td>Oklahoma</td>
</tr>
<tr>
<td>6.2%</td>
<td>Vermont</td>
<td>9.5%</td>
<td>Colorado</td>
</tr>
<tr>
<td>5.7%</td>
<td>Mississippi</td>
<td>8.9%</td>
<td>North Carolina</td>
</tr>
<tr>
<td>5.7%</td>
<td>Pennsylvania</td>
<td>7.4%</td>
<td>Pennsylvania</td>
</tr>
<tr>
<td>5.4%</td>
<td>Oklahoma</td>
<td>6.9%</td>
<td>Washington</td>
</tr>
<tr>
<td>4.9%</td>
<td>Wisconsin</td>
<td>6.7%</td>
<td>Vermont</td>
</tr>
<tr>
<td>4.8%</td>
<td>Alabama</td>
<td>6.5%</td>
<td>Alabama</td>
</tr>
<tr>
<td>4.5%</td>
<td>Minnesota</td>
<td>6.5%</td>
<td>D.C.</td>
</tr>
<tr>
<td>4.1%</td>
<td>Georgia</td>
<td>6.3%</td>
<td>Arkansas</td>
</tr>
<tr>
<td>4.1%</td>
<td>Arkansas</td>
<td>6.2%</td>
<td>Georgia</td>
</tr>
<tr>
<td>3.8%</td>
<td>Washington</td>
<td>5.7%</td>
<td>Wisconsin</td>
</tr>
<tr>
<td>3.5%</td>
<td>Delaware</td>
<td>5.1%</td>
<td>Iowa</td>
</tr>
</tbody>
</table>
Conference Draft

<table>
<thead>
<tr>
<th>Share of NUG Capacity</th>
<th>State</th>
<th>Share of NUG Generation</th>
<th>State</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.2%</td>
<td>Iowa</td>
<td>5.0%</td>
<td>Minnesota</td>
</tr>
<tr>
<td>3.1%</td>
<td>West Virginia</td>
<td>-4.3%</td>
<td>West Virginia</td>
</tr>
<tr>
<td>2.8%</td>
<td>Tennessee</td>
<td>4.1%</td>
<td>Tennessee</td>
</tr>
<tr>
<td>2.6%</td>
<td>Indiana</td>
<td>3.9%</td>
<td>South Carolina</td>
</tr>
<tr>
<td>2.5%</td>
<td>South Carolina</td>
<td>3.7%</td>
<td>Indiana</td>
</tr>
<tr>
<td>2.4%</td>
<td>Maryland</td>
<td>3.5%</td>
<td>Maryland</td>
</tr>
<tr>
<td>1.8%</td>
<td>Oregon</td>
<td>2.6%</td>
<td>Illinois</td>
</tr>
<tr>
<td>1.6%</td>
<td>Illinois</td>
<td>2.6%</td>
<td>Delaware</td>
</tr>
<tr>
<td>1.4%</td>
<td>Utah</td>
<td>1.9%</td>
<td>Oregon</td>
</tr>
<tr>
<td>1.3%</td>
<td>Montana</td>
<td>1.8%</td>
<td>Montana</td>
</tr>
<tr>
<td>1.2%</td>
<td>Ohio</td>
<td>1.3%</td>
<td>Ohio</td>
</tr>
<tr>
<td>0.7%</td>
<td>Wyoming</td>
<td>1.0%</td>
<td>Utah</td>
</tr>
<tr>
<td>0.6%</td>
<td>North Dakota</td>
<td>0.8%</td>
<td>Missouri</td>
</tr>
<tr>
<td>0.5%</td>
<td>Missouri</td>
<td>0.7%</td>
<td>Wyoming</td>
</tr>
<tr>
<td>0.4%</td>
<td>Kansas</td>
<td>0.5%</td>
<td>Nebraska</td>
</tr>
<tr>
<td>0.4%</td>
<td>Arizona</td>
<td>0.4%</td>
<td>Arizona</td>
</tr>
<tr>
<td>0.3%</td>
<td>D.C.</td>
<td>0.4%</td>
<td>North Dakota</td>
</tr>
<tr>
<td>0.3%</td>
<td>Nebraska</td>
<td>0.2%</td>
<td>New Mexico</td>
</tr>
<tr>
<td>0.2%</td>
<td>New Mexico</td>
<td>0.2%</td>
<td>Kansas</td>
</tr>
<tr>
<td>0.0%</td>
<td>Kentucky</td>
<td>0.0%</td>
<td>Kentucky</td>
</tr>
<tr>
<td>0.0%</td>
<td>South Dakota</td>
<td>0.0%</td>
<td>South Dakota</td>
</tr>
</tbody>
</table>


According to an EEI survey of utilities, utilities in ten states are paying over $37 billion in PURPA costs above their avoided costs. (See Table VII.4). As these data show, the PURPA problem is to a large extent concentrated in California and the Northeast. These states, not coincidentally, are among the states with the highest electricity prices. (See Table VII.4).

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3 Utilities in Florida, Hawaii, Idaho, Iowa, Minnesota, Montana, North Carolina, South Carolina, Virginia, Washington and West Virginia also indicated a PURPA problem, but did not provide numerical estimates.
Table VII.4. Payments to QFs above Avoided Costs and Retail Prices in the Ten States Reporting Biggest PURPA Problems

<table>
<thead>
<tr>
<th>State</th>
<th>Reported Amount of Payments above Current Avoided Costs (S Thousands, NPV)</th>
<th>Average Retail Electricity Price (¢/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>California</td>
<td>20,080,000</td>
<td>9.78</td>
</tr>
<tr>
<td>Connecticut</td>
<td>2,000,000</td>
<td>10.18</td>
</tr>
<tr>
<td>Maine</td>
<td>1,000,000</td>
<td>9.63</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>1,000,000</td>
<td>10.00</td>
</tr>
<tr>
<td>Michigan</td>
<td>300,000</td>
<td>7.09</td>
</tr>
<tr>
<td>New Jersey</td>
<td>2,610,000</td>
<td>10.06</td>
</tr>
<tr>
<td>New York</td>
<td>5,185,000</td>
<td>10.92</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>3,090,000</td>
<td>7.87</td>
</tr>
<tr>
<td>Texas</td>
<td>2,000,000</td>
<td>6.42</td>
</tr>
<tr>
<td>Vermont</td>
<td>12,500</td>
<td>9.13</td>
</tr>
<tr>
<td>Total / US AVG</td>
<td>37,277,500</td>
<td>6.91</td>
</tr>
</tbody>
</table>


Although states are now shortening contract periods and reducing the burdens associated with PURPA contracts in other ways, utilities are still being obligated to purchase power under terms they would not otherwise accept. While the costs of PURPA could be accommodated in a regulated market, continuance of PURPA is clearly inconsistent with competition. PURPA should be repealed as soon as possible, independent of any other legislative or regulatory reform.

PURPA repeal stops construction of new high-cost QFs, which is an important part of the problem. But repeal cannot, and should not, abrogate existing contracts, simply on the grounds that they are inefficient.

Nevertheless, there are mutually advantageous deals that can be made between utilities and QFs that are also in the interest of consumers. Utilities and QFs should be able to renegotiate, if it is in both their interests.
An efficient renegotiation of existing contracts would cancel contracts where the QF's variable costs exceed the market price of electricity. For example, take the case where the market price is four cents/kWh, the contract calls for the utility to purchase power from the QF for seven cents/kWh, and the QF's variable costs are six cents/kWh. The utility is losing three cents on every kWh it buys while the QF is making a profit of one cent on every kWh it sells. The total profit of both entities is minus two cents. Any deal where the utility pays the QF more than one and less than three cents per kWh not to produce is in both their interests. For example, if the utility pays two cents to the QF for every kWh it does not produce (or the present value of the two-cent revenue stream), the utility reduces its loss to two cents and the QF makes a profit of two cents. Both are made better off by not having a high-cost plant running. More importantly, an inefficient energy source has been shut down and costs to consumers are lower.

Some progress has been made in this area. By mid-1993, the utilities had bought out contracts for about 1,600MW. The terms of other contracts have been renegotiated. Respondents to an Edison Electric Institute survey of IOUs (accounting for 70 percent of IOU-served customers) had renegotiated a total of 232 contracts accounting for 8,573MW of capacity. Contracts representing another 4,257MW were under consideration for possible renegotiation.  

Even when the PURPA contracts are bought out or their terms renegotiated, utilities still will be left with significant stranded PURPA costs. This is primarily an equity

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issue, and should be dealt with in the same manner as other stranded costs, as we discuss in Section VIII.
VIII. STRANDED COSTS

Stranded costs—defined as the difference between the depreciated book value of a utility and its market value in a competitive marketplace—are a major obstacle in the transition to a competitive marketplace. The existence of stranded costs is prima facie evidence of the failure of the regulatory process to achieve its purported goal of producing a competitive outcome for consumers. The degree to which, and the manner in which, stranded costs are recovered are issues of great importance to both utility shareholders and ratepayers.

Stranded costs consist of investments and other expenses and contractual commitments that would not be recoverable in a competitive environment. The major categories are (1) nuclear generating assets; (2) other high-cost generating assets; (3) "regulatory assets" (operating costs that have been deferred); and (4) PURPA contracts.

 Estimates of stranded costs are in the range of $50 billion to $300 billion with a "best estimate" of $135 billion.¹ This compares with annual sales of investor-owned utilities of $168 billion;² a total industry equity value of $165 billion, and a total asset value of $570 billion.³ According to these estimates, failure to recover any stranded costs would reduce the market value of the electric utility industry by more than 80

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² EEI Statistical Yearbook, 64.
³ Moody's, 1995.
percent. For some utilities, stranded costs are in excess of the utility's equity value, and failure to recover them would lead to bankruptcy.

The stranded cost problem is exacerbated by restructuring proposals that deprive utilities of the full value of their transmission assets, and leave them with their devalued generation assets. As Irwin Steltzer has observed:

And, most dangerous of all, the world of the near-term future will be one in which the utilities' competitors will attempt to achieve an uneconomic combination, one that grafts the new, lower reproduction cost of generating power onto the old, lower depreciated original cost of moving it. Such a combination of economic reality and accounting fiction ignores the replacement cost of transmission and distribution facilities, reducing incentives to expand them, and creates an asymmetry that should be offensive to anyone opposed to stacked decks, loaded dice and the proverbial unlevel playing fields. Therein lies the industry's most urgent need: a de jure or de facto write-down of generation assets and a parallel controlled write-up of transmission and distribution assets.†

Permitting utilities to obtain the fair market value for both their transmission and generation assets, which our proposal would do, is therefore a partial solution to the problem of stranded costs. As discussed in the appendix to this section, allowing market-based pricing of transmission reduces stranded costs by about $75 billion, assuming the replacement cost of the transmission network is a rough indication of its market value.

Arguments For and Against Stranded Cost Compensation

There are persuasive arguments both for and against compensating utility shareholders for stranded costs. Arguments in favor of compensation include:\(^5\)

- Fairness requires recovery of stranded costs. Utilities have been party to a regulatory compact under which they agreed to a variety of service obligations in return for a regulatory rate of return on prudently incurred investment. Failure to provide for a reasonable level of recovery would leave investors with the value of their property expropriated by the change in the rules of the game. Some argue that this would constitute a "taking" under Article V of the Constitution.

- The allowed rate of return on utility investments does not incorporate compensation for the risk of stranding. The cost-of-capital calculations used in the regulatory process allow utilities to earn an average return assuming risks are symmetric around that rate. The possibility of stranded costs represents an asymmetry for which there is no offsetting possibility on the upside. This is even more true in the case of QF contracts, for which utilities earn a zero return.

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- Because stranded costs already have been incurred, the issue to a large extent is the division of those costs between consumers and shareholders, with minimal efficiency implications.
- The ability to earn a regulated rate of return on investments is like a contract the government has made with the utilities. To the extent that the government fails to adhere to its commitments, future investments by regulated companies will be seen as more risky and require a higher rate of return.
- Stranded costs can be recovered efficiently—through a neutral access charge or some other method that maintains neutrality so that suppliers compete on the basis of their incremental costs.
- Providing compensation removes the political opposition of those who are disadvantaged by a Pareto-superior deregulatory change.

Arguments on the other side of the stranded cost issue include: *

- There is no essential difference between regulated utilities and other firms. Some are winners and some are losers, but society does not generally compensate the losers.
- Electricity regulation is more like simple special-interest regulation than any grand regulatory compact.

• There is no clause in the regulatory compact, explicit or implicit, that requires the government to compensate utilities for stranded costs.

• Stranded investment is not a new phenomenon. Regulators previously have disallowed billions of dollars of investment. Compensation for stranded costs rewards those utilities with poorest foresight. A prudent utility should include political and regulatory risk in its calculations.

• Utilities had discretion to avoid stranded costs. For example, while some utilities went ahead with nuclear construction plans, many others canceled their projects. Shareholders at the time bore the cost of these write-offs.

• Many utility's shares are valued at more than book value, which may indicate that shareholders have already been compensated for their current situation.

• Stranded costs affect the distribution of wealth. What really matters, however, is economic efficiency and stranded cost compensation doesn't promote efficiency and may lead to inefficiencies. Specifically, to the extent the market fails to see the full price reduction possible from deregulation, and to increase production and consumption accordingly, there is a loss of allocative efficiency.⁷

In our view, there are good arguments on both sides of this issue and it is difficult to either favor or oppose stranded cost recovery without qualification. If the federal government preempts the states and mandates competition, it may then be reasonable

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to provide stranded cost compensation at the federal level. Moreover, as discussed below, there may be efficiency advantages to paying for stranded costs at the federal level. Whatever deregulatory bargain is struck between utilities and the government, the parameters of a solution to the stranded cost problem should be established simultaneously with the beginning of competition.

A stranded cost program consists of, first, a method of measuring stranded costs and, second, a method of paying for them. The determination of stranded costs should, as far as possible, be based on market measures rather than on regulatory proceedings that may take years and essentially relitigate past rate cases. Arriving at a market-based measure of stranded costs entails valuing the utility's assets in a competitive environment and then comparing this value to the utility's book value.

A good stranded cost program should be clearly transitional and should phase out in a prescribed manner and time frame. Most importantly, it should not be counterproductive to the pro-competitive goals it is intended to help achieve, and should not weaken incentives to avoid future stranded-cost problems.

Paying for Stranded Costs

Regulators: Transition from Regulation to Efficient Competition in Electric Power, Edison Electric Institute, 1995, p. 44.

* We will publish a specific proposal along these lines shortly
Once the amount of stranded cost compensation is determined, there remains the question of how to raise the money to pay the shareholders. Two available alternatives involve minimal economic distortion: a lump-sum access fee for hooking up with the transmission network; or, a transfer of funds from general revenues (i.e., a broad-based income tax). These methods are the least distorting because they do not affect the price of electricity and, therefore, consumption or production decisions. In comparison, a direct tax on electricity will produce distortions, because electricity consumption and production will be lower than they otherwise would be, given marginal production costs.

Since electricity consumption is virtually universal, the distributional consequences of a lump-sum access charge and an income tax may not be very different. While neither of these instruments affects consumption or production decisions at the margin, they may affect plant location decisions. In this respect, a federal program, which is uniform across states, may be preferable to a variety of different state plans, which may affect interstate locational decisions. A federal program does not perpetrate the mistakes of the past. Of course, a federal plan may affect international locational decisions. In addition, it may be viewed as inequitable for states which are responsible for large stranded costs to be able to shift them to states that operated more responsibly.
APPENDIX VIII-A

THE REPLACEMENT COST OF THE U.S. INVESTOR OWNED UTILITIES' TRANSMISSION SYSTEM

We derive a rough estimate of the replacement cost of the IOU transmission system by multiplying the construction cost per mile for lines of various voltages by the existing mileage of lines of that voltage. Transmission lines are defined as 138kV and higher. Table VIII-A.1 presents summarizes the existing IOU network in terms of circuit miles of overhead transmission lines, and Table VIII-A.2 summarizes the available data on transmission lines construction cost.

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Circuit Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>138 kV</td>
<td>63,611</td>
</tr>
<tr>
<td>230 kV</td>
<td>49,334</td>
</tr>
<tr>
<td>345 kV</td>
<td>39,956</td>
</tr>
<tr>
<td>500 kV</td>
<td>17,498</td>
</tr>
<tr>
<td>765 kV</td>
<td>2,388</td>
</tr>
</tbody>
</table>

Table VIII-A.2. Typical Costs of New Transmission Lines

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Supporting Tower</th>
<th>No. of Circuits</th>
<th>Size of Line (kcmil)</th>
<th>Normal Rating MW</th>
<th>Cost per Circuit Mile</th>
</tr>
</thead>
<tbody>
<tr>
<td>60 kV</td>
<td>wood pole</td>
<td>1</td>
<td>4/0 AWG</td>
<td>32</td>
<td>$120,000</td>
</tr>
<tr>
<td>60 kV</td>
<td>wood pole</td>
<td>1</td>
<td>397.5</td>
<td>56</td>
<td>$125,000</td>
</tr>
<tr>
<td>60 kV</td>
<td>wood pole</td>
<td>1</td>
<td>715.5</td>
<td>79</td>
<td>$130,000</td>
</tr>
<tr>
<td>115 kV</td>
<td>wood pole</td>
<td>1</td>
<td>4/0 AWG</td>
<td>6</td>
<td>$130,000</td>
</tr>
<tr>
<td>115 kV</td>
<td>wood pole</td>
<td>1</td>
<td>397.5</td>
<td>108</td>
<td>$135,000</td>
</tr>
<tr>
<td>115 kV</td>
<td>wood pole</td>
<td>1</td>
<td>715.5</td>
<td>151</td>
<td>$140,000</td>
</tr>
<tr>
<td>115 kV</td>
<td>steel pole</td>
<td>1</td>
<td>715.5</td>
<td>151</td>
<td>$250,000</td>
</tr>
<tr>
<td>115 kV</td>
<td>steel pole</td>
<td>1</td>
<td>715.5, bundled</td>
<td>302</td>
<td>$400,000</td>
</tr>
<tr>
<td>115 kV</td>
<td>steel pole</td>
<td>2</td>
<td>715.5</td>
<td>151</td>
<td>$160,000</td>
</tr>
<tr>
<td>115 kV</td>
<td>steel pole</td>
<td>2</td>
<td>715.5, bundled</td>
<td>302</td>
<td>$250,000</td>
</tr>
<tr>
<td>230 kV</td>
<td>steel pole</td>
<td>1</td>
<td>1,113</td>
<td>398</td>
<td>$360,000</td>
</tr>
<tr>
<td>230 kV</td>
<td>steel pole</td>
<td>1</td>
<td>1,113, bundled</td>
<td>796</td>
<td>$530,000</td>
</tr>
<tr>
<td>230 kV</td>
<td>steel pole</td>
<td>1</td>
<td>2,300, bundled</td>
<td>1,060</td>
<td>$840,000</td>
</tr>
<tr>
<td>230 kV</td>
<td>steel pole</td>
<td>2</td>
<td>1,113</td>
<td>398</td>
<td>$230,000</td>
</tr>
<tr>
<td>230 kV</td>
<td>steel pole</td>
<td>2</td>
<td>1,113, bundled</td>
<td>796</td>
<td>$350,000</td>
</tr>
<tr>
<td>230 kV</td>
<td>steel pole</td>
<td>2</td>
<td>1,300, bundled</td>
<td>1,060</td>
<td>$477,500</td>
</tr>
</tbody>
</table>


Information on the relative proportions of specific characteristics of lines within each voltage category is not available. Therefore, we assume that all line types (within a voltage category) are represented equally and calculate a simple average of the replacement costs for each voltage category, as shown in Table VIII-A.3.

Table VIII-A.3. Average Replacement Costs of Overhead Transmission Lines

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Average Replacement Costs per Circuit Mile</th>
</tr>
</thead>
<tbody>
<tr>
<td>60 kV</td>
<td>$125,000</td>
</tr>
<tr>
<td>115 kV</td>
<td>$222,500</td>
</tr>
<tr>
<td>230 kV</td>
<td>$477,500</td>
</tr>
</tbody>
</table>

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The replacement costs for 138 kV and 161 kV lines were filled in using a simple regression line.\(^1\) The replacement cost for 345, 500 and 765 kV lines was assumed to be the same as the same replacement cost for the 230 kV lines—$477,500 per circuit mile—which is a conservative assumption.\(^2\) Multiplying these unit cost estimates by the number of miles yields a replacement value of investor owned utilities' overhead transmission lines (see Table VIII-A.4).

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Circuit Miles</th>
<th>Costs per Circuit Mile</th>
<th>Replacement Value (thousands dollars)</th>
</tr>
</thead>
<tbody>
<tr>
<td>138</td>
<td>63,611</td>
<td>281,287</td>
<td>17,892,918</td>
</tr>
<tr>
<td>161</td>
<td>10,538</td>
<td>329,483</td>
<td>3,472,096</td>
</tr>
<tr>
<td>230</td>
<td>49,334</td>
<td>477,500</td>
<td>23,556,985</td>
</tr>
<tr>
<td>345</td>
<td>39,956</td>
<td>477,500</td>
<td>19,078,990</td>
</tr>
<tr>
<td>500</td>
<td>17,498</td>
<td>477,500</td>
<td>8,355,295</td>
</tr>
<tr>
<td>765</td>
<td>2,388</td>
<td>477,500</td>
<td>1,140,270</td>
</tr>
<tr>
<td>TOTAL</td>
<td></td>
<td></td>
<td>73,496,554</td>
</tr>
</tbody>
</table>

Thus, the replacement value of the IOU overhead transmission lines is $73.5 billion.

The overhead lines, however, are not the only component of the transmission system. There are also underground lines, substations and other equipment, for which we do not have data that would allow us to calculate the replacement value in the same way as we do for overhead lines. We therefore assume that the percentage difference between the replacement and book values is the same for all transmission assets as it is for overhead lines. Table VIII-A.5 presents the available book value data.

\(^1\) The equation was \(\text{COSTS} = -1894.5 + 2095.5 \times \text{VOLTAGE} \)
Table VIII-A.5. Book Value of IOU's Transmission Assets

<table>
<thead>
<tr>
<th>Item</th>
<th>Book Value (thousands of dollars)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land &amp; Land Rights</td>
<td>3,901,606</td>
</tr>
<tr>
<td>Structures &amp; Improvements</td>
<td>1,510,962</td>
</tr>
<tr>
<td>Station Equipment</td>
<td>25,483,765</td>
</tr>
<tr>
<td>Towers &amp; Fixtures</td>
<td>7,694,619</td>
</tr>
<tr>
<td>Poles &amp; Fixtures</td>
<td>8,123,753</td>
</tr>
<tr>
<td>Overhead Conductors &amp; Devices</td>
<td>11,680,723</td>
</tr>
<tr>
<td>Underground Conduit</td>
<td>1,119,845</td>
</tr>
<tr>
<td>Underground Conductors &amp;</td>
<td>1,512,712</td>
</tr>
<tr>
<td>Devices</td>
<td></td>
</tr>
<tr>
<td>Roads &amp; Trails</td>
<td>181,764</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>61,209,749</strong></td>
</tr>
<tr>
<td><strong>Total Overhead Lines</strong></td>
<td><strong>33,093,427</strong></td>
</tr>
</tbody>
</table>


The items in italics in Table VIII-A.5 make up the book value of the overhead transmission lines. As can be seen, the way we choose the items makes the estimate conservative: For example, some land and roads are certainly a part of station equipment or underground lines. Including them all in the book value of overhead lines lowers the replacement/book ratio for the overhead lines and hence lowers the estimate of the replacement value of the entire transmission system.

The book value of overhead transmission lines is $33.093 billion. Dividing the replacement value by the book value yields a ratio of 2.22. As indicated, we assume that this ratio is the same for the remaining transmission assets (underground lines and substations). Multiplying the book value of the entire transmission system by this ratio

\[2\text{ A rule of thumb for the average cost for new lines in the 230-765 kV range is $500,000 per mile. See}\]
gives us the estimate of the replacement value of the entire IOU transmission system, which is $135.940 billion (See Table VIII-A.6.)

<table>
<thead>
<tr>
<th>Item</th>
<th>Value (thousands dollars)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead Lines Book Value</td>
<td>33,093,427</td>
</tr>
<tr>
<td>Overhead Lines Replacement Value</td>
<td>73,496,554</td>
</tr>
<tr>
<td>Ratio Replacement/Book</td>
<td>2.22</td>
</tr>
<tr>
<td>All Transmission Assets Book Value</td>
<td>61,209,749</td>
</tr>
<tr>
<td>All Transmission Assets Replacement Value</td>
<td>135,939,552</td>
</tr>
<tr>
<td>Difference between Replacement and Book</td>
<td>74,729,803</td>
</tr>
</tbody>
</table>