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The State of Utility Securitization:

Stranded Costs and Other Tariff-Based Financings Opportunities, Risks and Rewards

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EXECUTIVE SUMMARY

State-by-State Analysis
Each state has its own rules and regulations governing electric utilities, one of the few remaining monopolies in America. The Federal government has direct jurisdiction over only 15% of the industry through the Federal Energy Regulatory Commission (FERC). Technology has advanced to the point that generating power no longer needs to be solely a local, distance restricted matter. There is a wide complex and efficient grid for distributing power to industrial and residential customers. It is now possible to "track" and charge for additions and subtractions from the grid with little regard to distance. National forces are pushing the industry to competition, but it is the states, for now, that will decide how to dismantle the monopoly and allow for competition at the power-generation level.

Deregulation
The objective of deregulation is to achieve a new competitive electric marketplace in which a deregulated electric power generation market works in unison with a regulated transmission and distribution market. In this environment, consumers will have direct access to a competitive market for electricity (retail wheeling), while the "natural" transmission and distribution monopolies remain in place.

Stranded Costs
The so-called "stranded costs," which encumber many regulated electric utilities, complicate the introduction of a competitive marketplace. Stranded costs are the power generation assets and obligations, currently included in the rates charged to customers, that may become uneconomic as a result of a new competitive generation and power supply market. These costs were undertaken initially as a result of legal requirements or with the understanding that they would be recovered in electric rates approved by the state's utility commission.

Special Tariffs/Transition Charges
To compensate utility shareholders for these stranded investments, some have proposed that utilities be granted the right to charge customers for portions of these possibly unrecoverable costs and accelerate and guarantee their recovery once and for all. Utility customers would be charged a special tariff that would be irrevocable, limited to a set period of time and collected by the utility regardless of where the customer buys electricity (non-bypassable). All or portions of this tariff can then be securitized through the sale of the right to this cash flow to a special-purpose vehicle that will issue securities backed by these irrevocable cash flows.

Securitization as a Refinancing Tool
The objective of securitization is to provide utilities with a lower cost of funds than traditional utility debt and equity. The reason we say "lower" is that the utilities have financed these assets already, with a combination of debt and equity. Customers are reimbursing the utility already for the debt and a "return" on the equity through the current rate base. So, when securitization of a special tariff or rate occurs, the utility will likely be required to use the proceeds to buy back existing higher-cost debt and equity, thus lowering its weighted-average cost of capital.

Benefits of Securitization (Tariff-Based Financings) with Deregulation
Securitization will allow the utilities to recover stranded investments (or any other investment approved by regulators) upfront rather than over time, eliminating any uncertainty about their recoverability. In addition, it will lower the overall financing costs of the utility as relatively costly equity and corporate debt are replaced with less expensive, secured, highly rated asset-backed securities (ABSs). In turn, the financing savings will be passed on to consumers through lower electric rates. The finality of securitization in recovering uneconomic costs reduces the utility's remaining business risk.

Securitization: A Wall Street Tool Used to Facilitate Deregulation
Securitization and deregulation are two separate and distinct programs that have been linked by the political process. But this is not a necessity. Moreover, in certain states, securitization may be able to occur without a supplemental state statute. According to independent and nationally recognized legal counsel, many states' local regulators may have sufficient authority under existing state laws to sanction utility tariff-based securitizations. Each program — deregulation or securitization — could proceed independent of the other. It may be advantageous for utilities to go this route. And Wall Street, regulators and counsel are finding new structures to protect investors and provide for triple-A rated securitization.

Status of Deregulation with Securitization
Prudential Securities Incorporated (PSI) estimates that those states with significant stranded-cost exposure include Arizona, California, Connecticut, Illinois, Louisiana, Maine, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania and Texas. Between 1996 and 1997, California, Illinois, Massachusetts, Montana, Pennsylvania and Rhode Island enacted electric restructuring bills and provided for stranded-cost recovery. The legislation in these states allows utilities to finance the recovery of large portions of their stranded costs by issuing bonds backed by special tariffs designed to recover such costs. Many other states have initiated legislation for electric utility restructuring or have begun to focus on the issue in some capacity.

A Key New Asset Class Emerges
There is the potential that this new class of ABS — stranded-cost securitizations or Rate-Reduction Bonds (RRBs) — will be sizable; estimates range from a low of $50 billion to a high of $150 billion in total issuance for all U.S. utilities over the next few years. PSI projects stranded-cost securitization issuance to reach

$10 to $15 billion in 1998. However, this figure is likely to be extremely volatile given the political, legal and regulatory obstacles that these deals must hurdle to reach fruition.

Why Stranded-Cost Securitizations Are Different

Unlike more traditional ABSs, the securitization of the special-tariff cash flows can result only from specific authorization by the appropriate state regulatory authority under existing legislation and/or a supplemental state statute. Either one may be sufficient depending on state law and Constitutional provisions. This is important because it is a newly designated stream of income (derived from the special tariff charged to a utility's customers), rather than the tangible stranded assets themselves, that are being securitized. The assets themselves may not be producing any income, but their cost is the basis for providing the tariff that Wall Street securitizes. The twist in securitizing stranded costs is that the continued right to collect this tariff from consumers must be irrevocable and non-bypassable — current or future utility commissions and/or state legislatures must not be able to alter this property right, and all customers must be required to pay it regardless of where they buy power. The alteration or rescission of this right presents a new risk to investors. However, most view this risk as remote if the foundation of the property right is properly established and counsel, as in other ABS transactions, presents the proper opinions.

Widespread Appeal to Investors

Cash-flow stability from electrical consumption patterns, high credit quality of the underlying asset (the tariff) and the efficiency, experience and therefore knowledge of the servicer (i.e., the utility itself) are the key attractions of these bonds for investors. Traditional ABS investors view stranded-cost securitizations as a means to diversify their more traditional ABS portfolio away from consumer debt. Traditional utility investors find the sector attractive given the lack of new utility corporate debt.

California First To Deregulate and Securitize

In late November and early December 1997, the three major California utilities sold $6 billion in RRBs. The bonds were extremely well received by the fixed-income marketplace. Some were 10 to 15 times oversubscribed and each successive deal came at tighter spreads than the previous issue. The securitizations helped provide residential and small utility consumers in California with a 10% rate cut.

Looking Forward: 1998

The good news is that the ABS marketplace has fully embraced stranded-cost securitizations. The bad news is that thus far demand far outstrips supply. In 1998, securitization and electric utility deregulation will begin the de-linking process, a fact that should hasten the pace of issuance.

Also in 1998, all participants involved will come to the realization that a *single template for utility securitization/tariff-based financing does not exist*. The issuance of RRBs will be a state-by-state procedure and issues such as the nature and dollar value of stranded costs, the powers of each state's utility commission and the political temperature in a given state will play key roles in determining the timing and size of securitizations. In certain states, according to the unqualified opinion of nationally recognized counsel, utilities may find that they will be able to issue RRBs without supplemental state legislation. In some states, the utility commission has the authority under existing state statutes and Constitutional precedents to put an irrevocable tariff in place for the recovery of stranded costs. In fact, in certain situations, securitization may be allowed to proceed even without attaching a specific stranded cost to the transaction. Already, the state of Illinois is permitting (albeit by new state statute) regulators to authorize tariff-based securitization regardless of whether it relates to stranded costs.

What's more, 1998 will likely bring about a broader definition of RRBs. It may be necessary to extend the amortization schedules of these securitizations in order to deliver immediate and substantial cost savings to rate payers. A large sticking point, even in those states in which securitization has been authorized, is the amount of immediate savings these transactions can deliver to customers. What we've learned is that the lower cost of financing versus traditional utility debt and equity gained by these transactions can be muted by the shortening of the amortization period for the recovery of these costs. Even though shorter amortization schedules lead to sizable reductions in total rate payer payments, they can lead to higher costs in the early years. Thus 1998 may usher the advent of 15-year final maturities on some RRBs to alleviate the rate pressures caused by amortization compression.

Another thorny issue expected to become more apparent in 1998 involves above-market power-purchase contracts and their impact on customer savings. These contracts are currently off-balance-sheet items and, as such, are treated only as an annual expense. However, should the stranded costs associated with these contracts be securitized, the large up-front payment (likely to be in *billions* of dollars) used to buy them out or down has to be amortized over the short life of the securitized debt (currently ten years). This will put further pressure on rate payer cost savings and pressure to extend final maturities.

A final key issue likely to develop in 1998 is the impact public pressure to cut rates in exchange for securitization will have on utility ratings. Securitization has the potential to enhance ratings by removing a major portion of business risk from the balance sheet. However, public pressure for large cost savings may lead to bigger buybacks of equity with securitization proceeds and thus to a more leveraged company whose ratings may, at best, be unchanged.

I. An Introduction to Tariff-Based Financings and Stranded-Cost Securitization

During the past few years, the asset-backed securities (ABS) market has evolved to include new asset and product types and has experienced phenomenal growth and sponsorship as a result. Since 1990, the size of the ABS market (in terms of annual new issuance) has grown from $48.3 billion to around $176 billion in 1997. Asset types include home-equity, manufactured-housing, home-improvement, corporate and student loans, credit-card and floor-plan receivables, auto and boat loans, equipment leases and high-yield bonds. The newest asset class to hit the ABS market is the special tariff given to reimburse electric utility stranded costs.

Prior to November 1997, there had been only one stranded-cost-like securitization — the $202 million Puget Power Conservation Grantor Trust 1995-1 (AAA/Aa2). The Puget Sound Power & Light deal was not technically a stranded-cost securitization, but rather a securitization of cash flow from conservation assets mandated by regulators.

The potential for this new class of ABSs could be sizable. Estimates range from a low of $50 billion to a high of $150 billion in total issuance for all U.S. utilities. The fact that some portions of these estimates rely on projections or assumptions as to the future price of energy and capacity needs explains, in part, the large variances in stranded-cost estimations. (See Section II, "What Are Stranded Costs and Why Are They So Controversial?")

In an October 1997 report,[1] Moody's estimated that stranded costs for U.S. investor owned utilities (IOUs) amounted to $132 billion. This figure, however, may be significantly understated. The United States Department of Energy, in a report issued in August 1997,[2] estimated that domestic electric utilities have total net stranded costs of between $72.3 and $168.7 billion, assuming that intense competition did not develop. With such competition, the Department concluded that stranded costs could amount to over $400 billion — "an amount roughly equal to the net assets of the entire industry."[3]

Where the New-Issue Supply Will Come From Next — Maybe

Prudential Securities Incorporated estimates that those states with significant stranded-cost exposure include Arizona, California, Connecticut, Illinois, Louisiana, Maine, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania and Texas.

Not all stranded costs will be securitized. The ultimate amount for each utility will depend on what the regulators and/or state legislatures deem appropriate and on each utility's own decision as to whether the gains outweigh the costs.

The Year That Wasn't

1997 was expected to be the year in which the securitization of stranded costs hit its stride. However, the development of this market has been slowed substantially by regulatory, legal and political obstacles.

Yet, while the pace of new issuance has been slower than initially expected, there are few who question the viability of this new asset class with investors. In fact, both Standard & Poor's and Moody's are projecting that the securitization of bank loans, power-company receivables and other "new assets" will be the fastest growing segment of the public asset-backed markets in 1998 and are beefing up their staffs in anticipation of the added workload as these deals come to market. Testament to the burgeoning sector's viability is this quotation from the Department of Energy:

> "The Department believes that it is appropriate to provide for a fair mechanism for the recovery of costs and benefits that are stranded as a consequence of the policy shift to competitive markets. We also see it as an important element of the transition."[4]

California Utilities Bring Inaugural Stranded-Cost Securitizations

Utilities in California were the first and only ones in 1997 to bring utility/tariff-based securitizations to market, but there are some 30 additional states considering similar programs. 1998 may see the issuance of tariff-based RRBs from utilities in Illinois, Massachusetts, Michigan, Montana, New York and Pennsylvania. Projections put total issuance of utility securitizations in 1998 at around $10 billion to $15 billion. However, this figure is likely to be extremely volatile.

A good example of why issuance estimates will be difficult and volatile is the current situation in Pennsylvania. A decision in late 1997 by Pennsylvania's Public Utility Commission (PPUC) caused more uncertainty regarding the timing of a Philadelphia Electric (PECO) deal, which has been delayed already a number of times due to legislative issues. PECO currently has the PPUC's approval for a $1.1 billion stranded-cost securitization. This figure is substantially less than what PECO would like to securitize and is only about one-fifth of the total amount PECO is authorized to collect through transition charges. The PUC has strongly implied that it will authorize PECO to securitize over $5 billion if it accepts a number of conditions imposed in the new decision. The entire state's securitization effort appears to be on hold while PECO pursues an appeal and otherwise considers its alternatives.

Why States Matter, Why There Is No Template

One of the common fallacies concerning stranded-cost recovery and Rate-Reduction Bonds is that the laws governing utilities are essentially the same in every state. Therefore, each state needs to enact fundamentally the same new law to permit recovery of stranded costs and to permit securitization of tariffs granted to finance the structured-bond issues.

The truth is that the laws governing utilities are peculiar to each state. The powers and scope of utility regulators vary tremendously. The definition of "property" varies. Very little, if anything, can be said with particularity about all 50 states, even though several principles are clear. For example, utility regulators in Arizona are not part of the executive or even the legislative branch. The Arizona state constitution established the Arizona Corporation Commission, which regulates utilities, as a separate branch of government.

Nor is the definition of "stranded cost" in any way uniform or fixed. Pennsylvania was one of the first to enact a new restructuring and securitization law, but those involved have been fighting for almost a year about the definition of stranded costs. Dollar estimates vary by the billions. California, Illinois and Massachusetts all have different definitions of dollar amounts. How could this be? Because it is a state-by-state analysis.

The Puget Sound Power and Light bond issue, readily acknowledged as the first triple-A rated utility tariff-based securitization, is vastly different in structure and scope from the California Infrastructure Bank transactions. Yet, each is thought of as the "template" for stranded-cost securitizations nationwide.

The market for traditional utility debt and equity has known about the wide variety of laws and regulation for some time. Utility securities have traded differently based on regulatory environments. Knowledgeable investors took the disparities into account when pricing securities.

It might be useful to have a new law for every new class of security in the asset-backed market. It might simplify things, or it might create new complications, e.g., Pennsylvania. However, it is not realistic to expect nor is it likely to happen. Investors must examine the legal framework of securitization in each state, the opinions of counsel and the diligence of the underwriters.

A Deregulated Electric Generation Market

The concept of securitizing electric utility assets with special tariffs arose as a result of the restructuring that is underway in the electric utility industry. Deregulation's objective is to achieve a competitive marketplace in which a deregulated generation market will work in unison with a regulated transmission and distribution market. In this environment, consumers will have direct access to a competitive market for generation (retail wheeling), while the "natural" transmission and distribution monopolies will remain in place.

Arrival at a competitive marketplace is complicated by the so-called "stranded assets" and/or "stranded costs" encumbering many regulated electric utilities. Stranded costs are the generation related assets and obligations that may become uneconomic as a result of a competitive generation market. Utilities undertook and financed these commitments as a result of legal requirements or with the understanding that they would be recoverable in rates approved by a state's utility commission. And, they were being recovered slowly (20 to 40 years), over time, in the current rates charged to customers.

Over the years, utilities have made significant generation related investments to keep pace not only with load growth, but also with regulatory, governmental and environmental mandates. Such investments have been financed already through the issuance of debt and shareholder equity. State regulatory authorities set customer rates at levels sufficient to recover the cost of these financings and provide a "fair return." Stranded costs are being recovered, just not fast enough given the near-term onset of competition.

A huge portion of the stranded-cost problem has arisen because many utilities also were required to enter into independent power purchase (IPP) contracts under the Public Utility Regulatory Policy Act of 1978 (PURPA). See Section III for details on this legislation. Mandatory IPP contracts typically involve purchasing power from independent non-utility generators (NUGs) at prices substantially in excess of current market prices.

Tariff-Based Securitization

In a deregulated, competitive marketplace, utilities have no assurance that they can charge rates to their customers that will allow them to fully recover stranded costs. In an effort to compensate utility investors for these investments, some have proposed that utilities be granted the right to charge customers for significant portions of these otherwise unrecoverable costs. These costs could be recoverable via a special tariff that would be irrevocable and limited to a set period of time in addition to accelerating the amortization of the cost itself. The special tariff is also referred to as a competitive transition charge (CTC), a fixed transition amount (FTA) and an intangible transition charge (ITC). All or portions of this tariff can then be securitized through the sale of the right to collect revenues from this tariff.

Securitization of the tariff allows the IOUs to recover allowable stranded investments upfront, rather than over time. The IOUs believe that stranded-cost securitization will lower their overall financing costs by replacing relatively costly equity and corporate debt with less expensive, secured, highly rated ABSs. In turn, the savings (the difference between the cost of funds and amortization periods) may be passed on to consumers via lower electric rates. (This simple formula leads to severe complications depending on the state and utility.)

IOUs also argue that competition will be hastened by allowing them a fair opportunity to expeditiously recover stranded costs so that they will have no need to oppose the development of a truly competitive generation market. By removing the uncertainty of recovery, they can embrace competition. *State utility commissions generally will have the authority to determine the recoverable amount of stranded costs.*

A State-by-State Analysis To Determine How It Will Be Done

The law will vary, on a state-by-state basis, as to whether the utility commission has the authority under existing state statutes and Constitutional precedents to put an irrevocable special tariff in place for the recovery of stranded costs from consumers or whether such action will require additional legislation. Between 1996 and 1997, California, Illinois, Massachusetts, Montana, Pennsylvania and Rhode Island enacted electric restructuring legislation providing for deregulation, stranded-cost recovery and securitization of the tariff. The legislation in these states allows utilities to finance the recovery of large portions of their stranded costs by issuing bonds backed by special tariffs designed to recover such costs.

In addition, many other states have initiated legislation for electric utility restructuring or have begun to focus on the issue in some capacity. As noted above, securitization and deregulation are not the same. Securitization is a new financing technique to the utilities.

Tariff-Based Securitization: Just a Low-Cost Financing Tool Caught Up in Controversy

How does a low-cost, triple-A rated financing technique acquire such a controversial reputation? Tariff-based securitization is becoming a dirty word in politics and with legislators across the country, primarily because of its association with electric utility deregulation. But it doesn't have to be that way.

Securitization is simply a low-cost financing tool. It is, however, new to the world of utility finance. In the past, utilities, under stringent regulatory oversight, have been able to use only plain-vanilla financing arrangements: generally straight debt, preferred stock and equity. When tariff-based securitization was first introduced to utilities, it had nothing to do with deregulation, stranded costs, nuclear facilities, NUG contracts or any other highly charged political issue. It was simply a low-cost financing tool for mandated conservation expenses, e.g., the Puget Power Conservation Trust.

The state of Illinois seems to have recognized this low-cost potential by permitting regulators to authorize tariff-based securitization of up to 50% of a utility's capitalization regardless of whether it relates to stranded costs. Other states may follow or develop their own ways to employ this financing technique.

The point is tariff-based securitization can lower a utility's cost of capital and thereby permit equivalent rate reductions. The use of proceeds is a separate and distinct issue. Regulators, who grant the tariff under existing law or supplemental legislation, will generally decide both the amount and the use of securitization proceeds. It is quite possible that after being co-opted by deregulation, tariff-based securitization may become just another corporate financing tool whose risks and rewards are weighed against other alternatives without regard to political issues.

Yet, the process of introducing competition is a complicated and multi-phased one, and the issue of stranded-cost securitization is only one step in the process. The fact that the first securitization of these costs did not occur until late 1997 is testament to the fact that securitization has proven to be a political "hot potato," as consumer advocates and other entities strongly oppose it, viewing stranded-cost recovery as tantamount to an IOU bailout, particularly when nuclear costs are involved.

It will be interesting to see the impact of 1998 state election-year dynamics on the outlook for securitization. Many sources we have talked with around the country believe that the desire to avoid political controversy in such an important year will prevent politicians in many states from endorsing securitization in 1998 — even if it means not showing progress in lowering electric rates and moving toward competition. However, if politicians decide voters want decisive action in these matters (most importantly, lower rates) even if this requires securitization, things may happen more quickly in 1998 than currently expected. Securitization might even proceed without additional legislation or regulation.

Is Supplemental Legislation Needed Everywhere?

If independent, nationally recognized counsel can provide unqualified opinions as to irrevocability and true sale under existing law in a certain state, supplemental legislation is not necessary. Indeed, pursuing legislation may lead to more controversy and delay. There may be a middle ground in which tariff-based financings receiving higher credit ratings under existing law can be used to provide low-cost financing for certain assets deemed to be "non-controversial." Other, more problematic stranded-cost issues could perhaps be resolved through national or state legislation. Again, it will be a state-by-state analysis. Investors will likely see a variety of proposals put forth in 1998.

II. WHAT ARE STRANDED COSTS AND WHY ARE THEY SO CONTROVERSIAL?

The Federal Energy Regulatory Commission (FERC) defines stranded costs as those costs that "utilities prudently incurred to serve customers under a regulated environment, and that could go unrecovered if customers switch to other suppliers." The FERC determined that the recovery of prudently incurred stranded costs is essential to insuring a fair and efficient transition to a market oriented electric industry. According to the FERC:

> "Utilities that made large capital investments or contractual commitments in the past under a different regulatory regime, and with the expectation of serving customers into the future, should have a fair opportunity to recover the costs if those customers under the competitive regime, leave the utility's system."

Most IOU stranded costs will relate to electricity generation, whether owned or purchased under PURPA mandated contracts from independent suppliers. This is because the generation portion of the business has experienced the most significant cost reductions and is most susceptible to competitive pricing pressures.

Stranded Costs: Three Major Categories

• **Nuclear Power Generation.** A large proportion of utility generating investments will be rendered uneconomical in a deregulated, competitive market. Such investments relate primarily to expensive nuclear reactors. The last major period of nuclear plant construction took place in the late 1970s and early 1980s in response to the nation's energy crisis and demands of the regulators to develop alternate power sources.

The combination of (i) a lack of incentive for cost containment (given the long-term full cost-recovery method of rate regulation then in effect), (ii) higher financing costs in an environment of double-digit interest rates and (iii) higher construction costs due to inflation and heightened attention to nuclear safeguards following the Three-Mile Island nuclear plant accident, drove up costs and lead times associated with nuclear plant construction.

Since then, new technologies, combined with affordable natural gas, have reduced the costs and lead times associated with the construction of alternative generating plants. This phenomenon has driven down generation costs to the point at which they are considerably lower than most utilities' embedded generation costs, thus, in effect "stranding" some of these costs. Securitization of the stranded-cost portion of the utility generation plant account on its balance sheet will, in effect, substitute cash for some of the plant. The cash then would be used to retire debt and/or equity to offset the reduced value of the generation plant.

• **Contracts to Purchase Power from Other Suppliers at Above-Market Rates.** When such contracts (IPPs, NUGs, etc.) require the purchase of power at prices above the current and expected wholesale market, they represent stranded costs. The utilities signed many such contracts in the 1980s at the urging of state regulators and even (particularly in California, Maine and New York) because state legislation or regulation effectively required utilities to sign them at the inflated prices. The popularity of the contracts was due to a number of factors, including:

— Loss of confidence in utility managed construction of generation as a result of the serious cost overruns in nuclear construction around the country,

— PURPA's mandate that new capacity requirements be met through "qualifying facilities" (QFs) if such facilities could make it available at the same or lower cost as the utilities' long-run "avoided cost" (the cost of building and operating new generating facilities), and

— The political popularity in many states (California and New York, for example) of PURPA QFs due to their environmental and energy-efficiency benefits — hastened by a growing anti-nuclear lobby.

Many of these above-market power-purchase contracts still have a long time (over 20 years) to run. The California legislation dealt with the problem by authorizing the state's three distribution utilities to recover the above-market component of these obligations from their customers as long as the contracts remain in effect. Alternatively, the utilities may buy out the contracts through upfront payments, which can then be recovered from customers. Such an upfront payment has the advantages of attaching a current value to all future obligations and saving money by getting some concession from the power producers (by eliminating default risk) in return for getting all their compensation upfront. Unlike stranded costs relating to investment in a generating facility, obligations to purchase power at above-market prices generally do no appear on the balance sheet unless there is a buy-out. A utility would most likely execute such a buy-out only if it could record a regulatory asset, which could then be recovered from rate payers. On the liability side, the utility would show the debt and/or equity used to finance the buy-out. A securitization would substitute cash for some or all of the regulatory asset and the cash would be used to retire debt and/or equity.

• **Other Regulatory Assets or Deferred Expenses.** When recovered through the traditional regulatory compact of costs plus rate of return, these assets and/or expenses (called "Regulatory Assets") cause the IOU to charge more for generation than the going market rate. Such assets or expenses include regulatory mandated expenditures for conservation and deferred capitalized operating costs. Utilities typically have a hodgepodge of such deferred costs on their balance sheets that non-regulated companies would not be permitted to capitalize. The rationale has been that utilities incurred these costs for the benefit of rate payers for a long time to come, which meant they should be amortized in rates over many years. All of that is changing. In the event of a securitization, cash would be substituted for regulatory assets and the cash would be used to retire a mixture of debt and/or equity.

Exhibit 1 provides a summary of where electric restructuring/securitization currently stands in many states around the country. We focus on states that are far along in the deregulation process, states where securitization may be imminent and on the IOUs believed to have significant amounts of stranded assets.

Exhibit 1: State-by-State Analysis of Electric Utility Deregulation and Securitization of Stranded Costs

Arizona

Authorization (Regulatory or Supplemental Legislation). The Arizona Corporation Commission is a separate branch of government under the Arizona Constitution. Independent and nationally recognized counsel has advised that it will likely not need separate legislative authorization for tariff-based financing/securitization.

Restructuring Plan. Both the Arizona legislature and the Arizona Corporation Commission (ACC) are groups studying the various issues involved in deregulating the state's electric utilities. It is unclear at this time which party has jurisdiction over deregulating the industry. The legislature argues that the ACC has the right to regulate utilities, but that it does not have the right to deregulate utilities. It is possible that this issue will not be resolved until a referendum is held to amend the ACC's charter. The next possible date for a referendum is the statewide elections scheduled to be held in November 1998. In the meantime, the ACC has authorized accelerated amortization of Arizona Pub. Svc.'s stranded costs and has adopted rules requiring the phase-in of retail competition beginning 1/1/99 with all customers to have choice by 1/1/03. Since then, legislation has been introduced providing competition for all by 12/31/99 as well as an upfront 10% rate reduction.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
Pinnacle West Corp. (AZ Pub. Svc.)	1,500*	NA	NA
Tucson Electric Power	0-1,000**	NA	NA

Source. *Estimated by PSI. Company has not provided this figure to the commission.** Estimated by company.

California

Authorization (Regulatory or Supplemental Legislation). Legislation enacted 9/96 (includes securitization).

Restructuring Plan. Retail access for all customers 1/1/98 (which has now been delayed to 3/31/98 due to software problems). Most non-securitized transition costs to be recovered by 3/31/02. Above-market power-purchase contracts to be recovered over the life of the contract. Two larger IOUs must divest fossil generation. Third, San Diego G&E also plans to divest. 10% initial rate reduction for residential and small commercial customers. Another substantial rate reduction is expected in April 2002.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
Pacific G&E	11,400	November 1997	2,900
So. Cal. Ed.	13,100 - 13,800	December 1997	2,500
San Diego G&E	1,900	December 1997	700

Source. Company filings

Exhibit 1 (Continued)

Illinois

Authorization (Regulatory or Supplemental Legislation). Legislation enacted 11/97 (includes securitization). Securitization permitted up to 50% of utility's capitalization whether or not it relates to stranded costs.

Restructuring Plan. Phase in of direct access beginning in 1999 for the largest customers with all having choice by 2002. Commonwealth Edison & Illinois Power required to reduce residential rates by 15% on 8/98 and 5% more in 2002. Smaller reductions expected for other Illinois electrics. CTC to be in place through 12/31/06 with a provision for its extension through 2008.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
Commonwealth Ed.	NA	1/2 in 8/98, 1/2 in 8/99	6,000
Illinois Power	NA	1/2 in 8/98, 1/2 in 8/99	1,600

Source. Companies and legislation.

Maine

Authorization (Regulatory or Supplemental Legislation). Restructuring legislation was signed into law in May 1997. A bill authorizing the use of securitization may be addressed in the 1998 session. Independent, nationally recognized counsel has advised that the utility commission may have sufficient authority under existing legislation to approve tariff-based financing/securitization.

Restructuring Plan. The restructuring law requires that the Public Utilities Commission undertake many rulemakings to implement competition in March 2000. The law also requires that Central Maine divest its generation by March 2000. Central Maine has been offered $846 million for its non-nuclear generation. It expects to lower rates 10% if the sale goes through.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
Central Maine Power	860*	NA	NA

Source. Central Maine Power. *Previously estimated at $1,300 million, but sale of fossil generation will dramatically lower the amount.

Massachusetts

Authorization (Regulatory or Supplemental Legislation). Legislation was passed in November 1997.

Restructuring Plan. Retail competition for all customers 3/1/98. 10% rate reduction for customers who stay with their original provider, another 5% reduction (adjusted for inflation) on 9/1/99. All utilities in the state are required to sell fossil generation before they will be permitted to use securitization.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
Boston Edison	2,000*	Pre 9/99	NA
Western Mass (sub of Northeast Utilities)	500	Pre 9/99	500
New England Power (generation sub of the New England Electric system)	2,000*	Pre 9/99	No Intention of Issuing Bonds

Source. Data provided by the companies. *BSE's and New England Power's stranded cost will be reduced as a result of contracts to sell generating facilities at prices above book value.

Exhibit 1 (Continued)

Michigan

Authorization (Regulatory or Supplemental Legislation). Interested parties, including Detroit Edison and Consumers Energy have been negotiating in an effort to develop consensus legislation. The PSC believes that supplemental legislation would be necessary for securitization but not for the rest of the restructuring effort. Independent, nationally recognized counsel has advised that the utility commission may have sufficient authority under existing legislation to approve tariff-based financing/securitization.

Restructuring Plan. The Michigan Public Service Commission (MPSC) issued an order to start competition for all customer classes in annual blocks of 2.5% of load beginning in 1998, but this may slip until 1/99. All customers would have choice on 1/1/02. The utilities have requested rehearings before the commission to clarify issues that were not clearly answered by the 10/97 restructuring order.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
Consumers Energy	1,800	NA	NA
Detroit Edison	2,500	NA	NA

Source. Most recent Michigan PUC order.

Montana

Authorization (Regulatory of Supplemental Legislation). Legislation enacted 5/97 (includes securitization). Legislature may return for 1998 special session to revisit restructuring.

Restructuring Plan. Utility commission to issue restructuring orders to introduce competition. Original electric retail access timetable: Large customers begin 7/1/98; all customers 7/1/02 but there may be a delay. Four-year rate freeze for residential customers. Montana Power intends to divest generation, even though this is not required. Enron legal action may delay restructuring.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
Montana Power			
Gas	70*	NA	70
Electric	NA**	NA	NA

Source. *Subject to change through Enron lawsuit. **MTP had estimated $200MM of stranded cost associated with the electric business, but divestiture of generation may mitigate this number.

Exhibit 1 (Continued)

New Jersey

Authorization (Regulatory or Supplemental Legislation). The companies have addressed the need for enabling legislation in order to implement the restructuring proposals and the use of securitization. The likelihood of legislation passing increased when Governor Christie Whitman won reelection in the fall of 1997. The legislature is expected to receive a bill for consideration as early as March. Independent, nationally recognized counsel has advised that the utility commission may have sufficient authority under existing legislation to approve tariff-based financing/securitization.

Restructuring Plan. On July 15, 1997, the state's four electric utilities filed restructuring proposals with the Board of Public Utilities (BPU) as was required by the BPU's final findings of April 1997. In the restructuring filings, each company addressed retail choice, rate reductions and stranded costs. The BPU recommends a phase in of customer choice beginning October 1, 1998, for 10% of the state's customers and for all customers by year-end 2000. Additionally, the BPU recommended a rate reduction of between 5% and 10%. BPU decisions on the restructuring proposals are due in May 1998.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
Atlantic City Electric & Gas	1,300	Late 1998	400
General Public Utilities (GPU)			
Jersey Central P&L	1,800	Late 1998	1,700
Pub. Svc. Electric & Gas	3,900 (Nuclear) 1,600 (NUG contracts)	Late 1998	2,500

Source. 1997 Company filings with BPU.

New Mexico

Authorization (Regulatory or Supplemental Legislation). The 1998 legislative session in New Mexico has expired with no action taken on restructuring. The utilities in New Mexico will look to the 1999 legislative session where it is hoped legislation will be passed that deregulates the industry and authorizes the PUC to determine stranded-cost levels and provide for their recovery. Independent, nationally recognized counsel has advised that the utility commission may have sufficient authority under existing legislation to approve tariff-based financing/securitization.

Restructuring Plan. The Public Utility Commission (PUC) ordered rate cases in the spring of 1997. However because of the collaborative restructuring effort, the rate cases were stayed. The collaborative efforts were not successful. When the collaborative effort failed, the PUC ordered the utilities in the state to file rate cases.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
El Paso Electric	173-248	NA	NA
Pub. Svc. Co. of NM	119-748	NA	NA

Source. Data provided by the companies' ECOM models and covers only the portion of cost in the New Mexico jurisdiction.

Exhibit 1 (Continued)

New York

Authorization (Regulatory or Supplemental Legislation). Legislation has been introduced but has not been acted upon. Independent, nationally recognized counsel has advised that the utility commission may have sufficient authority under existing legislation to approve tariff-based financing/securitization.

Restructuring Plan. Individual company rulings in the "Competitive Opportunities" proceeding provide for customer choice generally to be phased in by 2001. Rulings require the divestiture of substantial portions of the companies' fossil generating capacity and include varying rate reductions for smaller customers (e.g., 10% for Consolidated Edison and Rochester Gas & Electric; 5% for New York State Electric & Gas; 3% for Niagara Mohawk).

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
Con Edison	5,500 to 4,000*	NA	NA
New York State E & G	2,500*	NA	NA
Niagara Mohawk	6,000**	NA	NA
Rochester G & E	700**	NA	NA
Central Hudson	300**	NA	NA

Source. *Company estimate. **PSI estimate.

Ohio

Authorization (Regulatory or Supplemental Legislation). A bill addressing the issue of securitization has been introduced in the Ohio Legislature. Ohio must still resolve some very complex tax issues involving property tax reform before a court mandated deadline of March 1998. This issue coupled with the fact that 1998 is an election year would seem to indicate that 1998 will be a difficult year to pass legislation. However, with competitive legislation having passed in Illinois and Pennsylvania, the Ohio legislature may have the incentive needed to bring this issue to the forefront of public discussion.

Restructuring Plan. The co-chairmen of the Ohio General Assembly's Joint Select Committee on Electric Utility Deregulation issued their recommendations in December, but these did not purport to be a consensus view. The recommendations included retail choice for all customers by 2000 and rate reductions for all customers. Governor Voinovich has offered his support for electric competition and stated that four principals must be addressed in any legislation or report. They include: 1) quickly giving customers choice; 2) prevention of unfair marketing practices; 3) fair and equitable stranded-cost recovery; and 4) the need to collect enough tax revenue to maintain school funding.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
American Electric Power			
Ohio Power	Minimal	NA	NA
Columbus Southern*	300 - 500	NA	NA
First Energy Companies			
Cleveland Electric	3,200	NA	NA
Ohio Edison	4,500	NA	NA
Toledo Edison	2,200	NA	NA

Source. Data provided by the companies. *Columbus Southern's estimate is based on total investment in Zimmer less an estimated amount of depreciation.

Exhibit 1 (Continued)

Pennsylvania

Authorization (Regulatory or Supplemental Legislation). Legislation enacted 12/96 (includes securitization).

Restructuring Plan. Utility chooses which customers get access. First 33% have access by 1/1/99; 66% by 1/1/00; 100% by 1/1/01. Customers to receive initial rate reductions reflecting benefits of securitization. Restructuring proceedings currently held up due to competing plan for restructuring filed by Enron and commission restructuring order for PECO, which differed greatly from settlement and is under appeal.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
PECO	7,500*	NA	5,000**
Gen. Pub. Utilities (GPU)	2,700*		
Metropolitan Edison			
Penn Electric			
Duquesne	2,000***		
Penn. Power & Light	4,500*	1/1/99	
Allegheny Power	1,520*		

Source. *Company estimate in restructuring filings. ** Suggested in Commission Restructuring Order. ***Company's estimate at FYE 1997 estimate.

Texas

Authorization (Regulatory or Supplemental Legislation). Legislation failed to pass during the 1997 session, which means that the legislative session of 1999 is the next time electric utility deregulation can be considered. In the mean time, an interim seven-member committee has been established to study electric utility restructuring. The committee is expected to issue a status report by March 1, 1998 and a final report by October 1, 1998. Independent, nationally recognized counsel has advised that the utility commission may have sufficient authority under existing legislation to approve tariff-based financing/securitization.

Restructuring Plan. Texas Utilities and Houston P&L have reached transition-to-competition settlement agreements with the Public Utilities Commission of Texas (PUCT), which alleviate uncertainty about rates during 1998 and 1999 and put the debate back in the legislature. The settlement agreements mirror the Bush bill that was introduced this past fall in the legislature and offer rate reductions for residential customers. Two other companies (Texas New-Mexico Power and Entergy) have filed transition-to-competition plans with the PUCT. TNP has reached a settlement with the PUCT staff calling for rate reductions totaling about 9% and competition for all by 2003. Remaining stranded costs could continue to be recovered through a CTC until 2008. Entergy is actively negotiating with interested parties in the state and the PUCT in an attempt to reach consensus on a transition-to-competition plan. We expect most of the other utilities in the state to seek settlement agreements ahead of the 1999 legislative session.

		Securitization	
Utility	**Estimated Stranded Costs ($MM)**	**Date**	**Amount ($MM)**
Central Power & Light	3,000-1,600	NA	NA
El Paso Electric Co.	1,400-800	NA	NA
Entergy Gulf States	660-190	NA	NA
Houston P & L	6,400-1000	NA	NA
Texas-New Mexico Power	800-700	NA	NA
Texas Utilities	7,700-200	NA	NA

Source. Data obtained from the companies' ECOM filings with the Public Utility Commission of Texas (PUCT) assuming full retail access in 1998. PUCT will recalculate these numbers prior to the next legislative session beginning 1/99.

III. THE ELECTRIC UTILITY INDUSTRY IN TRANSITION: A BRIEF CHRONOLOGY

In the late 1970s, it became apparent that change was coming to the electric utility industry. Traditionally, IOUs held monopolistic control over the generation, transmission and distribution portions of the business. Consumers of electricity purchased power from government protected monopolies, and government regulators (based on cost-of-service regulation, not market forces) set wholesale electric rates.

In what was characterized as a "regulatory compact," the government granted to IOUs exclusive franchises in their areas in return for keeping rates at levels that reflected utility costs, including a reasonable rate of return for utility investors (shareholders). In addition, large-volume customers typically subsidized smaller ones in terms of how costs were allocated.

However, economic and technological changes over the past several years have led to new sources of generation that can be marketed at prices lower than all of the costs embodied in existing utility rates. *And consumers, particularly industrial and large commercial ones, are demanding access to these lower-cost producers.* The IOUs, faced with this emerging competitive market for wholesale power service, are in the process of reinventing themselves to face these new challenges.

A Benign Beginning — How Choice in Power Got Started

The Public Utility Regulatory Policy Act of 1978 (PURPA) created a new category of electric business, the "qualifying facility" (QF), which laid the groundwork for choice for the electricity consumer. PURPA encouraged cogeneration and small power production by requiring electric utilities to buy electric energy from, and sell electric energy to, facilities that met certain criteria. These transactions were to occur at "avoided cost," which is the cost the utility would have incurred to generate or purchase the next most expensive increment of power elsewhere (i.e., the cost that was "avoided"). The costs were estimated, sometimes on assumptions that have proven wildly inaccurate. While the impetus behind the passage of PURPA was the oil crisis of the 1970s, it served to pry open the monopolistic nature of the electric utility industry by adding QFs to the generation mix. It was PURPA that stimulated the growth of independent power producers (IPPs).

The National Energy Policy Act of 1992 (EP Act) proved to be the most significant in the move toward deregulating the industry, as it highlighted the Federal Government's commitment toward deregulation. The objective of the EP Act was to open the *wholesale* electricity market through a transmission system that was available to all on a comparable basis. The EP Act mandated, as did orders later adapted by the FERC, that transmission owning utilities allow other utilities, independent electric generating companies and electric marketers access to transmission lines (so-called "wholesale wheeling"). Also, independent generating companies owning and operating generation facilities that sell their output only at wholesale were exempted by the EP Act from the restrictions of the Public Utility Holding Company Act of 1935 on the multistate ownership and operation of such facilities. The EP Act encouraged the growth of IPPs and allowed buyers and sellers to reach each other via its transmission-line access provisions.

A Recognition of Reality

Issued in April 1996, FERC's Order Nos. 888 and 889 fulfilled the directives set forth in the EP Act, effectively allowing competition in wholesale generation markets to begin. In its 1996 annual report, FERC stated that:

> ***The Commission's major achievement in this fiscal year was the restructuring of wholesale electric power service with Order Nos. 888 and 889. This will bring unprecedented competition to the industry, save consumers billions of dollars, and pave the way for state sanctioned retail competition.***

The commission estimated in this report that electric utility restructuring would result in savings of $3.8 to $5.4 billion each year and provide other benefits, such as new market mechanisms and technological innovations. Orders 888 and 889 require IOUs that own, control or operate transmission lines to file nondiscriminatory open-access tariffs that offer others the same transmission services they provide to themselves and at the same costs.

Specifically, Order No. 888 provides for the full recovery of certain stranded costs subject to FERC jurisdiction that were prudently incurred prior to July 11, 1995, to serve power customers. Such stranded costs could otherwise be unrecoverable if customers use open access to move to another electric supplier.

Federal Versus States — States Win

While FERC jurisdiction encompasses only about 10% to 15% of the assets of the IOU industry, the finding was influential and served notice that if state regulators did not follow suit, the Federal government might intervene and override them.

Since the EP Act of 1992, individual states have expanded the concept of choosing one's electric supplier from the wholesale level to the retail level. Congress has begun to consider legislation that would deregulate the retail electricity markets, but currently there appears to be little consensus as to how to accomplish the task, and much controversy. It is more likely that the states will be the major determinants in the retail deregulation process. In an April 21, 1997 Prudential Securities *Legislative Update*, entitled "Congress Could Deregulate Electric Utilities, But Only After Lengthy Debate," PSI analysts conclude that "intense lobbying and a lack of consensus in the Congress will make the passage of electric restructuring legislation a multi-year process." They go on to explain that Federal legislation is likely to set a certain starting date for retail choice to begin, and compel the states to allow the utilities a reasonable opportunity to recover stranded costs. It would also likely grandfather in any state restructuring plans that had already been approved by a particular date, provided they met certain basic criteria.[5]

Learning from Congress and The Telecommunications Act of 1996

Congress passed the Telecommunications Act of 1996 in February 1996, which was intended to end the Regional Bell Operating Companies' (RBOCs') monopolistic control over the local telephone systems in exchange for the RBOC's entry into the long distance market. This process, which Congress envisioned taking little more than a year, has been hampered by legal challenges by the RBOCs, long distance companies and state regulators. Implementation of a fully competitive market is uncertain.

For this reason, Congress may be hesitant to legislatively mandate competition in the electric utility industry any time soon. We believe that lessons learned from the Telecommunication Act may have convinced Congress it is much less contentious to let the states deregulate themselves. Furthermore, now that the process of deregulation has started at the state level, it is only natural that other states follow in order to remain competitive with their neighbors in attracting and retaining business.

IV. ACCELERATED RECOVERY AND REFINANCING OF STRANDED COSTS THROUGH SPECIAL TARIFFS

Traditionally, state utility commissions set electric rates at levels sufficient to recover, and earn a return on, prudently incurred costs — so-called "just and reasonable rates." However, in a deregulated, competitive environment, IOUs will be competitively constrained from charging rates sufficient to cover such operating and capital costs in the generation sector. The inability to recover prudently incurred investments and costs could prove a considerable hardship to a number of utilities, causing significant financial deterioration or even utility insolvency.

The timing of retail competition is of key importance, particularly for higher-cost, less-competitive utilities striving to maintain their financial integrity. For such utilities, an aggressive schedule for retail access may mean that there is insufficient time to prepare. Such events would, of course, impair the credit quality of the IOU.

To provide for the recovery of stranded assets and facilitate the move toward a deregulated electric industry, IOUs are seeking a special, non-bypassable tariff, commonly (although not exclusively) referred to as a competitive transition charge (CTC).

Determining What and How Much Is Recoverable

Recoverable Costs: Different States, Different Status

In order to be recoverable through a transition plan, a stranded cost must be considered by regulators as "just and reasonable" and to have been "prudently incurred." These are the same standards required in order to recover costs through the traditional utility regulatory process. In most cases, recoverable costs under a transition plan will have been deemed to be recoverable already under traditional regulation, although, in some cases (e.g., buy out of NUG contracts), no regulatory body would yet have had an appropriate occasion to reach a decision on this point.

To find that a certain amount of investment in a generating facility should be recovered from rate payers as a stranded cost, it will be necessary to choose a methodology for determining how much rate payers must pay and what will be left for them versus the utility at the end of the transition period. In what follows, we highlight some of the plans proposed and/or implemented thus far to address this problem.

- **California.** The basic assumption was that all nuclear investment would essentially turn out to be stranded and should therefore be included in the stranded costs eligible for recovery during the transition period. However, a specific provision was made for a 50/50 sharing between the utility and rate payers of any remaining value in the nuclear plants at the end of the transition period, so that rate payers would not lose if the plants turned out to have value. Once a certain fixed amount of stranded cost of a given type is recovered, no more is permitted and that element must be removed from the revenue requirement. (See "Section VI. A Case Study: California" for further details on the deregulation and securitization process in California.)

- **Illinois.** Commonwealth Edison and Illinois Power, the two companies with significant stranded costs in the state of Illinois, are allowed to charge customers a certain specified level of rates for a specified period of time. They also may impose a transition charge, according to a preset formula, if a customer goes to another supplier. Under this plan, there is no determination of the amount of stranded cost, nor does there need to be. The utilities simply substitute cash raised through a securitization (up to half of their capitalization as per the legislation) for some of the generating plant or regulatory assets on the balance sheet. They then use the cash to retire a mixture of debt and equity. In this manner, securitization allows for the refinancing of some of the debt and equity on the balance sheet without the necessity of specifying which individual assets are to be securitized.

- **PECO Energy Settlement.** The utility was allowed recovery of a certain amount of stranded cost and the right to charge rates at a certain level for a certain period of time. The utility was to be permitted to keep the extra funds if this resulted in the collection of more than the guaranteed amount. While legislation has been in place for over a year, an acrimonious debate has ensued over the amount of stranded investment and how savings will be passed on to customers.

Stranded Costs: Known and Measurable

An additional requirement for costs to be securitized is that they be "known and measurable." The objective is to prevent securitization of the right to reimbursement for an "open ended" obligation, like nuclear decommissioning, for example, and/or a string of usage based future payments, such as those required by an IPP contract. Presumably, the only way to accelerate recovery of such costs through a securitization would be to negotiate an upfront buyout price with the power

The State Regulatory Process: How a Rate Order/Tariff Becomes Irrevocable and Eligible for a True Sale

Puget Power, California Infrastructure Bank and others, whether under existing law or supplemental legislation, follow the same procedure — the regulatory process — to establish finality of the special tariff used in securitization. Though each state is different, here's a brief description of a typical procedure.

Scope of Legal Authority

Investor-owned electric utilities are regulated by the state utility commission for the state in which they sell power to retail and industrial customers. Such commissions are often called the Public Utility Commission or the Public Service Commission. Regulation by these commissions includes oversight of the quality of service and determination of rates (tariffs) to be charged. The duties, characteristics and authority of each state's commission are determined by the laws of the state. Typical areas specified by law include the setting of procedures for deciding cases (amount of time the process may take, restrictions on commissioner interactions with each other and the interested parties, etc.), the role of the consumer advocate and commission staff and how long the commission may exist in its present form without new legislative authorization.

Rigorous Due Process

Decisions concerning rates and special tariffs are made by means of a fully adjudicated process conducted in accordance with established commission procedure and applicable state law. (Puget Power and California followed this process.) A rate review (or other commission proceeding) typically involves the filing of testimony by the interested parties (the utility, the staff of the commission, various customer groups, etc.). Public hearings are held before a hearing officer or administrative law judge; briefs and reply briefs are filed; and typically the hearing officer prepares a recommended decision for the commission. Once the commission decides the case, there is often a right to request a rehearing within a limited time period. This is followed by a right to appeal the commission's final order on rehearing or denial of rehearing to the judicial system within a specified time period following the action on rehearing. While rate orders are generally effective when they are final (even though subject to appeal), commissions will often delay their effectiveness if there is a legitimate basis for delaying until a decision on appeal is handed down. In addition, a court may intervene and grant a stay of the commission's order if there is a credible threat of immediate harm during the appeal period.

Full Judicial Review

The existing state utility statute usually specifies the appropriate court for the initial appeals of the commission's final order. This is generally a state district trial court or an intermediate state appellate court from which appeals to the state supreme court may be made. The scope of appeals is often limited by statute to certain issues that may be reviewed and to the basis or standard of review to be applied for any reversal of the commission's decision. Commission orders may be reviewed by the Federal courts when they involve a Federal statute, an interference with interstate commerce or the issue of Federal preemption or supremacy. A final state appellate court decision could be appealed to the United States Supreme Court on the grounds that the commission's order violates the Federal Constitution. Only when all state and Federal appeals are exhausted is the commission's order final and non-appealable. For stranded-cost securitization/tariff-based financings, this will be true whether a new statute or existing state law is determined to be sufficient to authorize the irrevocable tariff and its sale to investors.

supplier. The right to recover this price from rate payers could then be securitized. (For example, in New York, Niagara Mohawk ultimately may securitize a portion of a $3.6 billion upfront payment of this sort.)

In determining total recoverable stranded costs, many regulators will likely want to net stranded asset amounts against estimated "benefits" the utility may have accumulated, such as generating facilities with a market value in excess of book. To address the latter, many utilities may be forced to sell their non-nuclear generating facilities and adjust their recoverable stranded generating investment to take into account any excess over book they are able to obtain.

Lastly, some questions may arise in different states concerning whether various assets should be assigned to the generation side of the business and perhaps be considered "stranded" or assigned to transmission and distribution, where they could continue to be recovered from customers in the normal fashion. Ultimately, such decisions will have to be made for every utility that will be required to unbundle its rates.

Description of the Non-Bypassable Tariff or Competitive Transaction Charge (CTC)

The CTC will be used by the IOU to repay debt and buy back equity issued to finance past investments and to buy out/buy down ongoing above-market power purchases, nuclear decommissioning reserves, etc. The CTC is a "non-bypassable" tariff applied to both present and future consumers for the recovery of the stranded investment.

"Non-bypassable" means that applicable consumers cannot avoid paying the CTC if they choose, when deregulation occurs, to purchase electricity from a supplier other than the initial IOU. Should the consumer leave the grid, an exit fee may be charged.

The CTC may be imposed on residential, commercial and industrial retail customers and collected through a separate, usage-based charge on the customer's bill. Going forward, a portion of the customer rate generally will be allocated to the CTC and another portion will go toward electricity and service.

The CTC amount will be based on customer usage and the rate will be set by the relevant state utility regulatory commission. The CTC amount will be set at levels that, in view of the utility's consumption forecasts, will amortize the aggregate amount of the stranded assets in accordance with the projected amortization schedule. In theory, levying a CTC might increase some customers' electric rates because it generally is expected to provide for accelerated stranded-cost recovery by shortening the amortization period of the asset that is currently reflected in rates. Remember, customers are already paying for these costs. However, in practice, political expediency argues against shortening amortization periods sufficiently to actually cause rate increases in the short term.

V. SECURITIZATION OF THE TARIFFS INTO RATE-REDUCTION BONDS

The securitization of stranded-cost recovery tariffs (or CTCs) and thus the issuance of RRBs are expected to be important tools in the restructuring of the electric utility industry. Until late 1997, there had been only one publicly offered securitization of a regulatory tariff — the $202 million Puget Power Conservation Grantor Trust in July 1995. Notably, the Puget Power transaction had no relation to electric utility deregulation or restructuring. However, more recently, securitization has become linked with deregulation, restructuring and stranded-cost recovery. For example, in late-November and early-December 1997, the three major California utilities came to market with $6.0 billion in stranded-cost securitizations. Going forward, however, tariff-based securitization may become just another corporate financing tool whose risks and rewards are weighed against other alternatives without regard to political issues.

First Round of Stranded-Cost Securitizations Wildly Successful

The California securitizations were extremely well received by the fixed-income marketplace as evidenced by the fact that they were some 10 to 15 times oversubscribed and that each successive deal was issued at tighter spreads than the previous issue. The key attractions of these bonds for investors are their cash-flow stability, high credit quality of the underlying asset and efficiency, experience and knowledge of the servicer (i.e., the utility itself).

Key Benefits of Securitization

The securitization of stranded-cost recovery tariffs will benefit not only consumers directly but also the utilities indirectly. The objectives of the IOUs are to lower customer rates and reduce their risk of non-recovery of stranded costs. In 1996, the utilities in California recognized the benefits achievable in the restructuring process from securitizing their rights to recover future CTC charges from their customers. As a result, securitization became one of the linchpins that made the September 1996 legislation acceptable to those utilities and customers by affording a 10% rate reduction.

Benefits to Utilities

• Reduction in customer rates and thereby improvement in the utility's competitive position.

• Certain and rapid recovery of a set amount of stranded costs, thus reducing the utility's financial and business risk.

• Lowering the weighted-average cost of capital (WACC) by replacing the various types of higher-cost capital normally available to a utility with low-cost, double-A and triple-A rated asset backed financings. Depending on the state and utility, the specific use of the proceeds will be either mandated via legislation or regulatory authority or left to the discretion of the utility. In most cases, the proceeds from securitization will be used to pay down the utility's corporate debt and engage in stock buyback programs in a proportion that reflects the desired future capitalization ratios, thus shrinking the balance sheet. Most utilities are currently financed by both equity and debt in about a 50/50 split.

• More flexibility for a utility to negotiate a buy out or buy down of above-market power-purchase contracts. Funding IPP contract buy-out/buy-down payments through securitization affords IOUs debt financing (which is cheaper than using a mix of debt and equity) without harming the utility's general credit. It also assures the utility that the buy-out/buy-down cost will be considered recoverable in its entirety, which dramatically reduces the risk to the utility from spending a large sum now to buy out/ buy down obligations stretching far into the future.

Benefits to Consumers

• Lower electric rates in the near term due to savings in the cost of capital as a result of securitization.

• Large savings in financing costs over the longer term due to the faster recovery of stranded costs (10 to 15 years) versus the normal 20- to 40-year period.

In Exhibit 2 (on pages 22 and 23), we explore the issue of how consumers benefit from securitization. In our analysis, we use a hypothetical utility, "ABC Energy Co." Note from Exhibit 2 that the revenue requirement in this hypothetical example is impacted by three major factors:

• The reduced cost of capital (debt and equity),

• The change in the annual amortization requirement, and

• The price of a buy-out/buy-down of NUG contracts.

The greatest reduction in the revenue requirement (-$48 million) comes from the reduced cost of capital from the stock buy-back program. Note how little is saved from the retiring of outstanding debt. In fact, when the cost associated with retiring higher-coupon debt (making those bond investors whole) is factored into the equation, it is possible that the -$1 million in

Exhibit 2: The Effects of Securitization on Hypothetical ABC Energy Co.

"ABC Energy Co."
($ in Millions)

In 1998, Utility Issues RRBs (15-Yr. Amortization) @ 6.5% $1,800

Where the Cost Savings Come From:
Impact of Securitization on Revenue Requirement — Year One

Reduces Revenue Requirement	**Increases Revenue Requirement**
• Refinancing ....-$49	• Change in Annual Amortization Requirement $8
By Type	
Debt .... -$1	
Equity ....-$48	
• Buy-Out/Buy-Down of NUG Contracts .....-$29	

Total Change in Revenue Requirement = -$70

Breakdown of year one by Type of Savings

• Refinancing - Equity

- Reduce equity with proceeds from sale of RRBs.
- Savings result from difference between pre-tax cost of equity and pre-tax cost of securitization.
- In the case of ABC Energy Co., assume 4/5 of the refinancing utility asset securitization proceeds ($400MM) are used to buy back common equity, thus reducing the book value of equity eligible to earn the authorized return from ratepayers by $400. (Actual buyback will be at market, not book. But for regulatory WACC purposes, earnings are calculated at book.)

$$= \quad \$400 \ X \left(\frac{12\%}{(1\text{-}T)} - 6.5\% \right)$$

= ***-$48 in Reduced Cost of Capital — Equity***

Where

$400	=	4/5 of securitization proceeds/equity to be retired
12%	=	After-Tax Cost of Equity (Return allowed on equity by regulators has no direct relationship to dividend)
6.5%	=	Pre-Tax Cost of Securitization
T	=	Tax Rate of 35%

It is appropriate to attribute these savings to securitization because, absent the added assurance of stranded-cost recovery securitization provides, it would be difficult/impossible to persuade the rating agencies to allow such aggressive refinancing of common equity with debt without a significant downgrade.

Exhibit 2 (Continued)

• Refinancing — Debt

- Reduce debt with proceeds from sale of RRBs.
- Calculated by replacing individual high-coupon bond issues with lower-cost securitization.
- For ABC Energy Co., we assume securitization will save 100 basis points as 1/5 of the refinancing utility asset securitization proceeds ($100 MM) is used to buy back debt with an average cost of 7.5%.

= $100 X (7.5% - 6.5%)
= $100 X 0.01
= -$1 in Reduced Cost of Capital — Debt

Where

$100	=	1/5 of the securitization proceeds/debt to be retired
7.5%	=	Average cost of the debt to be retired
6.5%	=	Cost of the securitized bonds

• Buy Out/Buy Down of NUG Contracts

— Securitization may facilitate the buy out or buy down of the above-market portion of power-purchase contracts.
— ABC Energy Co. is obligated to make annual payments of $200 million in excess of the current market price to the IPP for the next 20 years.
— Present valued by 10%, the total value of the above-market portion of the contract is $1.7 billion. The IPP agrees to a $1.3 billion upfront buyout/buydown to avoid taking the risk of not being paid for the full 20 years.
— The resulting savings are calculated by:

= Original Annual Above-Market Cost - Annual Cost of Securitization
= $200 - $171
= -$29 Buy Out/Buy Down of NUG Contracts

Where

Annual Cost of Securitization = First-Year Amortization of Principal + First-Year Financing Cost
= $87 + $84 (1,300/15) + 1,300 x 0.065
= $171

• Change in Annual Amortization Requirement: Effect of Amortization Compression

— Assume bonds sold to finance securitization are retired in equal amounts annually over a 15-year period (level-pay amortization).
— If amortization schedule for the original utility assets is also 15 years, there is no change in the annual amortization amount included in the revenue requirement as a result of the securitization.
— However, ABC's generating facility would have been amortized over 20 years, so securitization shortens the amortization period by five years, thus increasing the annual revenue requirement by $8 million in year one.

= ($500/15 Yrs.) - ($500/20 Yrs.)
= $33 - $25
= +$8 Change in Annual Amortization Requirement

Where

$500	=	Refinancing Utility Asset Securitization Proceeds
20 Yrs.	=	Original Amortization Period
15 Yrs.	=	Stranded-Cost Securitization Amortization Period

revenue-requirement reduction actually becomes an increase.

A reduction in the revenue requirement of -$29 million comes as the result of the buy out/buy down of the above-market portion of the utility's power-purchase contracts. Finally, the change in the annual amortization (from 20 years to 15 years) has a negative impact on the revenue requirement, adding some $8 million in annual cost. The reason for this is ABC's generating facility would have been amortized over 20 years. Securitization shortened the amortization period by five years (from 20 to 15), thus increasing the annual revenue requirement. This effect is known as "amortization compression."

Exhibit 2 affords a snapshot of the impact of securitization on the revenue requirement for year one. In Exhibit 3, we show the impact of securitization on the revenue requirement for the current recovery period, comparing total cost savings from issuing either a 10- or 15-year amortizing RRB. The stranded costs in Exhibit 3 are the same shown in Exhibit 2 for ABC Energy Co.'s generating facility and NUG contracts.

From the exhibit, we can draw several conclusions. Firstly, regardless of whether the utility opts for a 10-year or 15-year amortization period for the recovery of stranded costs (10- or 15-year RRBs), the revenue requirement falls dramatically versus the current schedule of 30 years for the generating facility and 20 years for the NUG contracts. Thus, in both cases, there are customer savings. In total, the buy-down/buy-out of the NUG contracts and the refinancing of the generating facility reduce the revenue requirement by a total of $3.024 billion if a 15-year amortizing RRB is used and $3.317 billion if a 10-year amortizing RRB is used.

Secondly, as for the two different amortization schedules, in general, the 15-year RRBs afford greater savings in the up-front years than do 10-year RRBs, but higher costs over the entire recovery period. Specifically, for the NUG contracts, the 15-year amortization schedule allows for greater rate payer savings in years one through ten. In fact, the 10-year plan actually increases the revenue requirement in years one and two. However, the total cost savings from the buy-out/buy-down of the NUG contracts for the 10-year amortizing RRBs are greater than they are for the 15-year RRBs, saving ratepayers an additional $211 million.

The same pattern exhibited for NUG contracts is also exhibited for the generating facility. In this case, however, both the 10- and the 15-year RRBs provide rate payers with savings immediately, the difference is that the 15-year RRBs provide greater savings in the early years than do the 10-year RRBs. Again, however, the 15-year RRBs for the generating facility afford less total savings than do the 10-year RRBs.

This trade-off, between up-front versus total savings, largely because of amortization compression, will complicate the resolution of stranded-cost recovery and may slow the issuance of RRBs. In general, to gain public support, some immediate and sizable rate payer benefit needs to be shown -- which, in many cases, will be difficult to do.

The Securitization Process

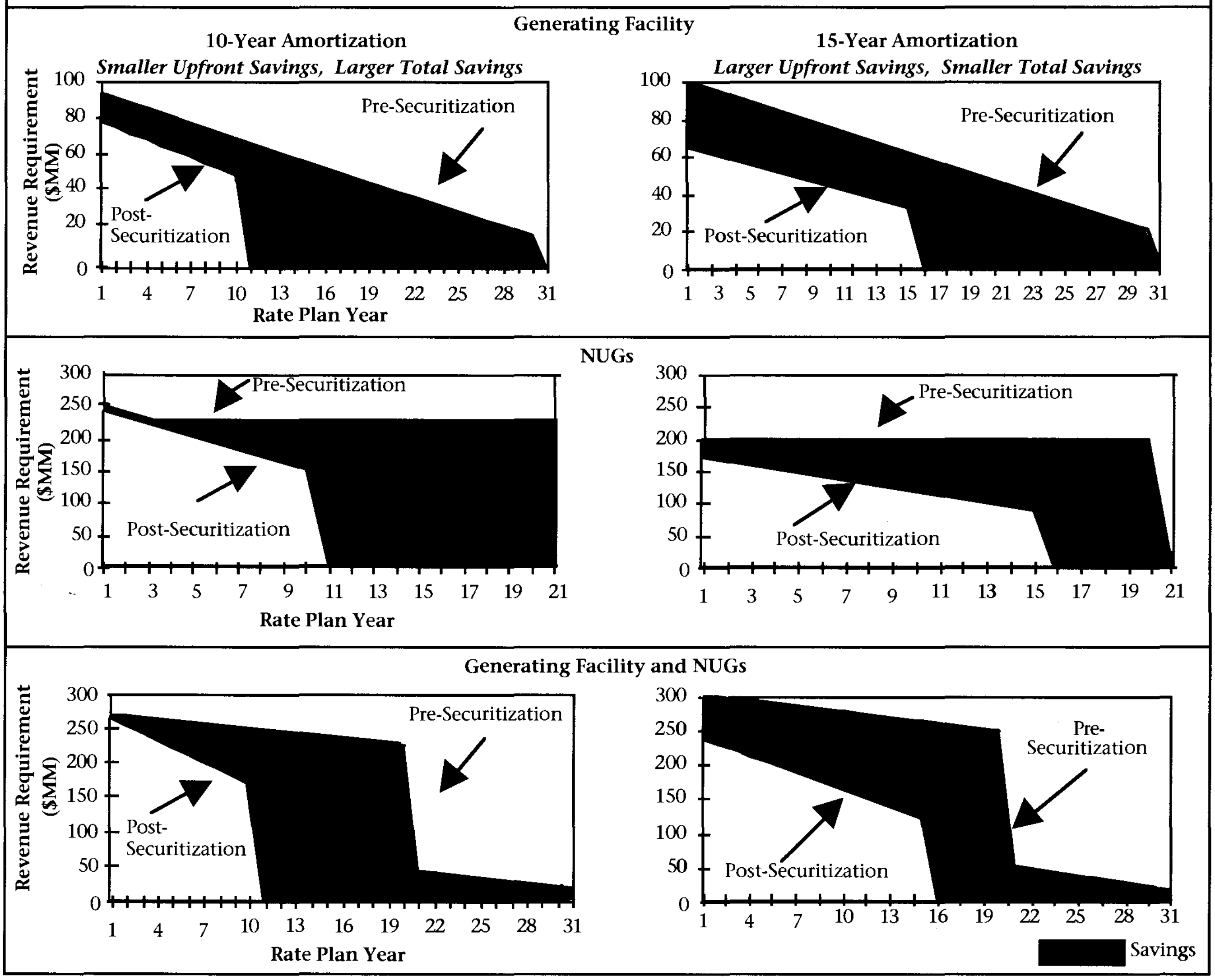
Unlike more traditional ABSs, the securitization of utility CTC cash flows can come about only through authorization by the appropriate state regulatory commission and/or by state statute. The three California securitizations were authorized via a new state statute, with the legislature laying out the framework for deregulation and securitization and the California PUC (CPUC) providing the final authorization. Of note, supplemental legislation may not be needed in every state.

Existing regulatory authority and/or legislation allow the IOU to transfer or sell the rights to the CTC cash flows to a bankruptcy remote special-purpose vehicle (SPV). The SPV will have an independent member on the board of directors, and its actions are limited to the acquisition of assets and issuance of the securitization debt. The SPV in turn issues securities backed by the future cash flow from the CTCs. The proceeds of the securitizations are remitted to the IOUs in payment for selling the property right to receive the CTC to the SPV. In this manner, the IOUs are able to recoup their stranded costs immediately and with certainty, as opposed to over a number of years via ongoing CTC charges.

In addition to providing for the securitization of the CTC, existing regulatory authority or supplemental legislation must ensure the irrevocability of the utility's right to collect the CTC. A regulatory rate order, which comes about either as a result of the PUC directly or via supplemental legislation that additionally authorizes the PUC to create the proper rate order, typically designates the revenue from the CTC as a vested property right. (For further details on property rights, please see the section on credit-quality issues beginning on page 27.)

The size of the securitization will be determined by the amount of costs to be recovered and securitized as approved by either regulatory procedures under state law or additional legislation. Not all costs deemed to be recoverable will be allowed to be securitized. As for the term of these securities, in most cases, this will be determined by

Exhibit 3: Amortization Compression: Impact on Revenues To Be Collected from Utility Customers (Revenue Requirement) — Pre/Post Securitization



the term of the transition period, which is a function of either the legislative or regulatory package for a given utility. The tradeoff between upfront and total savings in connection with the issues raised by amortization compression will drive the transaction. Generally speaking, the term will be between 10 and 15 years.

Structure Summary

As noted earlier, existing regulatory authority and/or supplemental state legislation is required to permit securitization of stranded costs based on special tariffs. Each state's particular situation will cause the mechanics and structure of individual securitizations to differ from state to state. However, the general RRB structure should be similar. In its simplest form, the IOU sells its legal rights to the non-bypassable CTC to an SPV. The SPV will be composed almost entirely of debt; the utilities will contribute some 50 basis points of the total as equity. The SPV purchases the right by issuing RRBs.

Assuming the California structures are indicative of future deals, bonds will be structured as fixed-rate and possibly floating-rate amortizing, multi-class securities with final maturities of 10 to 15 years, weighted average lives of less than one and up to ten years and credit support provided by various equity, reserve and overcollateralization accounts, as well as a true-up mechanism. The sequential-pay structure allocates principal from the entire pool to successive designated tranches until each class is paid in full.

In addition, as in the California deals, the bonds are expected to generally have tight principal payment windows and "preset" sinking-fund schedules. Should floating-rate issues be included in the structure, the trust will enter into a swap agreement under which the trust will pay a fixed-rate to a swap counter party and the swap counter party will pay to the trust a floating rate based on the principal balance of the floating-rate class.

Sizable Savings Take Time: The Simple Truth That Could Slow the Growth of Stranded-Cost Securitizations

Securitization has not been enthusiastically embraced by the political process in most states. Why? One reason is that years of keeping electricity rates low by stretching out amortization periods or keeping costs off balance sheets have created complications in achieving sizable and immediate public benefits from this method of financing. One of the key reasons securitization is promoted to, and accepted by, regulators and politicians for stranded-cost recovery is that it can produce immediate savings in customer electric rates — the rate reduction in RRBs. If you can replace high-cost debt (greater than 7%) and equity (greater than 15%) with low-cost securitized debt (6.5%), enormous savings can be generated and passed on to rate payers.

The problem is that this is not a traditional corporate financing that pays interest periodically and principal at maturity. It is similar to a mortgage in which principal and interest is paid off over the life of the security. And since it's like a mortgage, the amortization schedule is a big determinant of the total monthly bill. Longer amortization periods produce lower customer payments than shorter amortization periods. A simple example is that, generally, if a mortgagor refinanced from a ten-year mortgage to a 30-year, the monthly payment declines, alternatively, if a mortgagor refinances from a 30-year to a ten-year then the monthly payment increases.

Unfortunately for most utility stranded-cost securitizations, this simplicity of finance creates a great complexity in the political battle over RRBs. Remember, stranded-cost securitizations are a refinancing of costs already approved by the regulators and incorporated in the rate base. In most cases, regulators approved recovery of these costs with very long repayment/amortization periods (usually 20 to 30 years). However, with securitization, amortization periods need to be shorter, generally 10 to 15 years (see Exhibit 3 for an analysis of the savings produced by issuing 10- or 15-year RRBs).

The problem arises as the shortening in stranded-cost amortization periods (amortization compression) generally acts to offset the immediate savings in the net cost of financing. In sum, the positive impact (i.e., reduction) on the revenue requirement from a reduced weighted average cost of capital is substantially offset by the shortening in the amortization period for the recovery of stranded costs. Cumulative or total savings, compared to what rate payers would have paid over the original financing period, would be large and dramatic. Just like in a mortgage refinancing, large amounts of interest expense are avoided in the later years from having retired the debt so much sooner. But the upfront savings will be smaller.

When regulators and utilities address NUG/IPP contracts, it becomes even more onerous to produce upfront savings. These above-market contracts are currently off-balance-sheet — they are contracts and are only an annual expense item. When they are securitized, the large up-front payment used to buy out/buy down the contract has to be amortized over the short life of the securitized debt e.g., ten years. Therefore, no immediate reduction in revenue requirement will generally be realized when they are put on the balance sheet and paid off. Yet, long term, the savings also could be significant.

So, how did California do it? Didn't they produce immediate savings of 10% or more for rate payers with securitization? Yes, they did. But, there are two main reasons why California is not a template for the nation: First, California utilities had been given accelerated cost recovery of their nuclear plants. They were going to recover much of the amounts in question over the next four years — rates had been high because of the more rapid recovery regulators granted them. The ten-year securitization constituted a refinancing of these four-year costs into a ten-year cost. The extended maturities, therefore, allowed for lower rates. Second, in addition to extending the amortization of the high nuclear plant costs, changes in another high-cost factor in California — independent power-purchase contracts — artificially created savings. Rates were going to be reduced already as the contracts expired. The combination of extending the amortization periods with predictable contract cost reductions allowed for the ten percent savings. Unfortunately, for most other utilities in the country, this situation is unlikely to be repeated.

Sizable savings take time. So, while securitization remains a win-win for investors, utilities and rate payers, don't expect new-issue volume to be driven by the lure of immediate savings. Utilities might have to kick in some savings out of shareholder pockets in order to get stranded-cost securitization moving.

The result is a capless floater that shifts the trust's risk of floating rates to the swap counterparty.

The swap agreement will be terminated if the swap counterparty's rating by either Moody's or S&P falls below triple-A and the swap agreement is not assigned to a swap counterparty that satisfies such rating criteria. In this event, the interest-rate payable on the floating-rate securities will convert permanently to a fixed interest rate equal to the interest rate on the related class of notes, which may be substantially less than the rate otherwise payable on the floating-rate class. In the event of such a conversion to a fixed interest rate, both the liquidity and the market value of the floater may be adversely affected. There is no effect on the CTC, and, therefore, on the rate payer.

Principal will be allocated on a quarterly basis as follows:

• Trustee fee and unpaid trustee fees from previous distributions,

• Servicing fee and unpaid servicing fees from previous distributions,

• Certificate holders' interest and unpaid interest from previous distributions and certificate holder principal.

Exhibit 4 provides a simple schematic of the generic structure of a stranded-cost securitization.

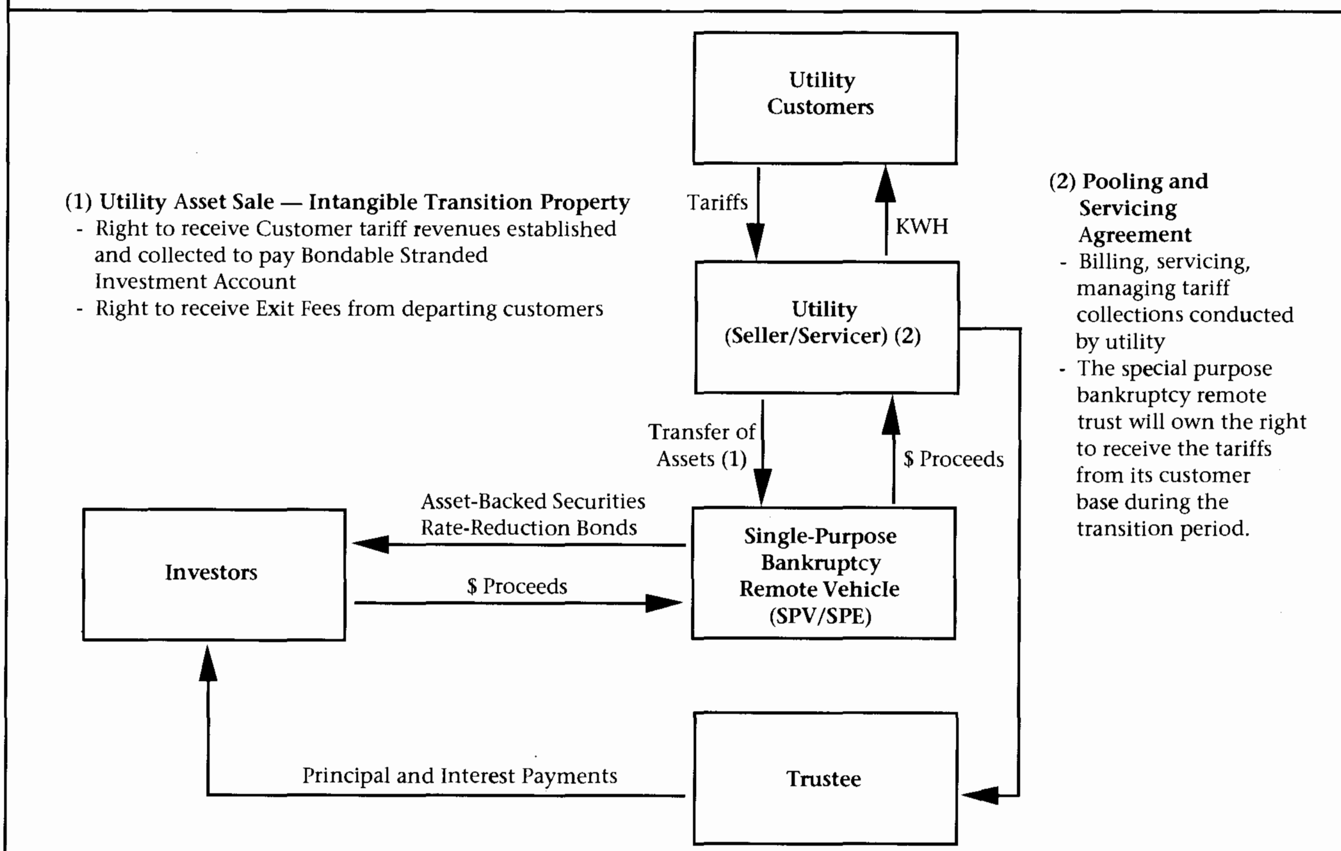
Asset Credit Quality and Credit Support

As the assessment and collection of the CTC are not dependent on the utility and the necessary moneys are allocated to the CTC before the utility receives its share, a utility asset securitization can achieve a credit rating that is higher than that of the utility's senior debt. Notably, no governmental agency nor instrumentality nor the utility itself guarantees or ensures the RRBs. For example, in the case of California, neither the full faith and credit nor the taxing power of the State of California is involved in the payment of principal and/or interest on the bonds.

Irrevocability of the CTC

Vital to assessing the credit risk associated with Rate-Reduction Bonds is a proper evaluation of the regulation or supplemental legislation that created the CTC. A unique credit concern associated with Rate-Reduction Bonds is the issue of the irrevocability of the CTC. There are concerns that a substantial economic downturn in the region may lead to efforts to alter the law/rate order, which could negatively impact the securitization.

Exhibit 4: Schematic of Securitization of Utility Stranded-Cost Recovery Assets



It is the creation of the property right that prevents rescission or alteration of the regulatory rate order that authorizes the CTC, and thus eliminates a key source of uncertainty.

To ensure the irrevocability of the utility's right to collect the CTC and facilitate the securitization of the CTC, a regulatory rate order, which comes about either through the PUC directly under existing legislative authority or through supplemental legislation that authorizes the PUC to create the proper rate order, typically establishes the revenue from the CTC as a vested property right.

Counsel has advised that, under the Constitution, the "Takings" clause of the Fifth Amendment protects property rights. The clause says that the Federal government may not take private property without making just compensation. Under the Fourteenth Amendment, that applies to states as well, and most state constitutions echo the "Takings" clause. There is a taking of property when government action "confiscates" the utility's ability to earn a fair return on its investment. This Constitutional protection, however, given historical precedent, is highly unlikely to be called upon. This is because regulatory rate orders covering the types of costs associated with stranded-cost securitizations have never been overturned.

Examples of this have occurred in New York in connection with the Shoreham, Sterling and Storm King canceled projects. In these cases, the New York State Public Service Commission (NYSPSC) authorized substantial recovery in rates, even though the projects were cancelled and never produced any electricity. The courts upheld this decision even after a challenge by consumer advocates and the New York Attorney General.

It is noteworthy for regulatory or administrative securitizations that the NYSPSC also made extremely strong statements about the irrevocability of the Long Island Lighting Company (LILCO) multi-year financial stability agreement at the time of its adoption. The reader will recall that in 1989 LILCO agreed to close the Shoreham nuclear facility in return for the right to recover and earn a return on the unamortized balance of the Shoreham regulatory asset. Because securitization (or tariff-based financing) had neither emerged in the utility world nor developed to its current level of sophistication, LILCO did not consider it an alternative at that time. These NYSPC statements, aside from their general probative value, could also serve the same purpose as the "legislative pledge" in structural/legal terms. It is interesting to speculate whether LILCO should have pursued a securitization in 1989.

In addition, in the case of the California securitizations, the state has pledged not to amend or alter the transition property unless adequate provision is made, by law, for the protection of the certificate holders. This provision itself, however, is subject to legislative amendment.

Future Fee Generation/Energy Consumption Patterns

Much like the securitization of future receivables, stranded-cost securitizations involve an analysis of the revenue stream (the tariff) from fees not assessed or billed to consumers upon the issuance of the bonds. The ability to properly amortize the RRBs depends largely on future fee generation, which depends largely on energy consumption.

In the case of the California securitizations, the CTC charge is based on kilowatt hours of usage by the applicable customers. Thus the aggregate amount of the CTC collected and the rate of principal amortization of the notes depends in part on actual energy usage by customers and the rate of delinquencies and write-offs. It's possible that demand for electricity could change or an economic downturn could de-stabilize the collection of cash surcharges.

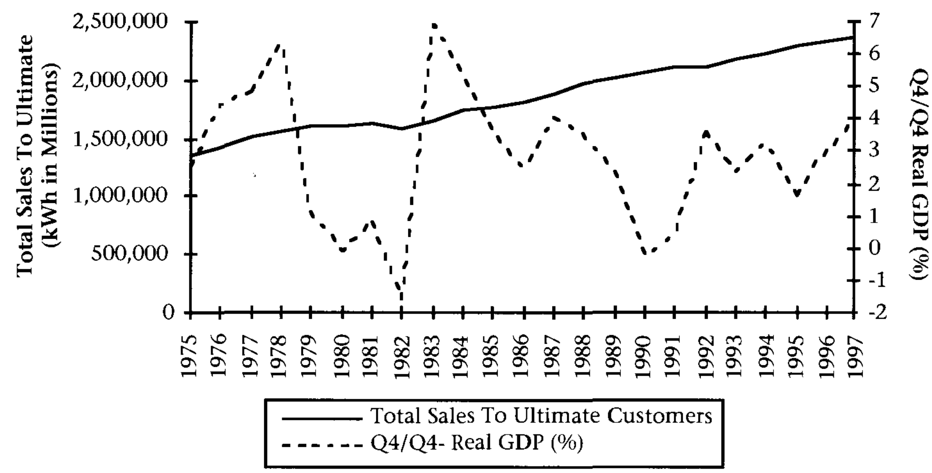
However, if the CTC is very small in both relative and absolute terms and the period during which the CTC amortizes the bonds is short, it is less likely that consumers will alter their consumption patterns during the term of the debt. Over longer periods, the potential for technological advances become greater, as does the potential for consumers to alter their consumption patterns. In Section VI, we review the actual price per KWH charged to the average rate payer. Note that in the Pacific Gas & Electric Case, the FTA amount is just 15.2% of the total customer bill.

In general, cash flows generated by utility customers tend to be quite stable and predictable over time. Electricity is a necessity and an essential service. Exhibit 5 on page 29 displays energy sales by IOUs in terms of kilowatt hours over the past ten years. The fact that usage has grown at a very stable pace even in the face of changing economic conditions reinforces this claim.

Changes in the customer base, technological advances, defaults in bill payments and economic cycles are just a few factors that could cause the CTC amount to be more or less than the amount necessary to amortize the notes in accordance with the stated amortization schedule. These factors are "credit risks," as they have the potential to impact the ability of the CTC revenues to fully

Exhibit 5: Electricity Consumption Patterns Versus Real GDP Growth

Very Stable Despite Wide Swings in Economic Growth



Source. Statistical Year Book of the Electric Utility Industry, 1996.

amortize the assets. Factors that could impact CTC collection include:

• **Changes in Energy Consumption**

— **Demographics.** Significant shifts in the future population of the area serviced. The most dire circumstance would be one in which the customer base shrinks to a point to which the transition charge becomes unacceptable to those who remain on the grid. In addition, if the customer base is too narrowly defined, the utility must rely on too few customers, potentially leading to more variable cash flows. The fact that the California securitizations are backed by tariffs levied against residential and small-commercial customers only is beneficial in that it reduces the potential volatility caused by a handful of key industrial entities leaving or entering the grid, or the impact that economic downturns have on industrial activity and thus electricity consumption. Residential customers are desirable in that their bills tend to be smaller and more diversified, they have fewer options for leaving the distribution system and they tend to pay their bills promptly and more reliably given the risk of service disconnection.

— **Sensitivity to Seasonal Variations and Weather.** While electricity consumption does shift in response to seasonal variations and weather, the utility incorporates such shifts into their consumption forecasts.

— Technological Advances. The possibility does exist that technological advances will alter energy consumption patterns dramatically. New technologies could cause consumers to switch energy sources outright or avoid the use of the IOU's grid altogether. Notably, given the current state of technology, such concerns do not appear to be a near-term issue and would be more of an issue 25 years or so in the future.

— **Price of Electricity and the Price/Availability of Competing Energy Sources.** Residential consumers are less price sensitive than are large commercial/industrial users. Larger consumers are more likely to flee the area serviced by the utility or seek price concessions or energy alternatives.

• **Utility's Historical Collection and Charge-Off Experience.** Delinquency and charge-off rates in the electric utility industry tend to be very low. For example, San Diego Gas & Electric's net write-offs as a percentage of billed revenues for residential, commercial and industrial customers has held at or below 30 basis points during the 1992 through 1996 period and at just 18 basis points during the first nine months of 1997. What's more, individual IOUs have extensive experience with and knowledge of the consumer base and have put in place deposit or guarantee procedures for certain accounts, along with credit scoring systems to determine the creditworthiness of new customers.

• **Accuracy of Utility's Projections of Population and Consumption.** The CTC amount is determined by utility forecasts of the customer base and consumption patterns into the future. The IOUs have an impressive track record of accurately projecting these factors, having several decades of experience doing so using various econometric models and substantial historical data. For example, San Diego Gas & Electric's annual forecasts for the years 1992 through 1996 varied by only zero to 3.4% from recorded consumption.

Unlike the mortgage related ABS sectors, stranded-cost cash flows bear no correlation with interest rates, thus eliminating the prepayment and volatility issues associated with these sectors.

Credit-Support Mechanisms

Credit support for stranded-cost securitization can take the form of overcollateralization, subordination, financial guarantees, a true-up mechanism, third-party insurance and/or reserve and equity accounts. Credit-support levels on stranded-cost securitizations will be low compared to the levels required for other asset types.

For example, in the Puget Power issue, rated AAA/Aa2, a true-up mechanism and overcollateralization were used as credit support; the overcollateralization amount was just 0.12% of the original certificate balance (because the overcollateralization is a flat dollar amount, the enhancement will increase on a percentage basis as the certificates amortize).

In the case of the California securitizations, the overcollateralization account was a mere 50 basis points. The availability of the true-up and the projected stability of fee revenue were the main drivers behind the expected lower credit-support levels on these securitizations.

The "True-Up" Mechanism

A true-up mechanism adjusts the tariff levied on consumers if the actual amount collected is less or more than that forecast by the utility. It acts as a form of credit enhancement for stranded-cost securitizations and ultimately allows for increased stability in cash flows. A true-up is just one form of credit enhancement available for RRBs.

In general, a true-up mechanism adjusts the tariff at regular intervals based on the actual versus projected amortization of the bonds. In particular, a true-up allows for the continuous calculation of current payments, the re-evaluation of projected payments to be received, comparisons of current and projected payments to scheduled interest and principal payments due the Rate-Reduction Bonds and the ability to alter the collection schedule to ensure timely payment of the bonds. Provisions for a true-up mechanism will be authorized by either regulation and/or legislation. Both the California and Pennsylvania legislation mandate that any orders authorizing transition bonds include true-up mechanisms.

Proposals by the utility to adjust the tariff through the standard true-up must be approved by the regulatory commission, but such approval should be formulaic and required by statute or the initial order. In the Puget Power Conservation Grantor Trust, a true-up mechanism kicks in if there is more than a 2% variance in the trust's actual versus projected balance. If there is more than a 2% variance, projections are re-forecast and an application made for a new tariff schedule sufficient to amortize the securities to return to the projected amortization schedule. Specifically, Puget determines annually if the unamortized bondable conservation investment amount varies from the projected bondable conservation amount by 2% or more. If it does, Puget recalculates the tariff based on updated customer forecasts in order to keep the amortization of the assets on schedule. The revised tariff must be submitted to the Washington Utilities and Transportation Commission within 30 days after the calculation date. While the commission has up to 11 months to approve the proposed revision, a delay of more than 30 days after the filing will extend the tariff termination date by the length of the delay. The final distribution of principal and interest to the certificate holders will always be six months following the tariff termination date.

In the case of California, the servicer is required to file a True-Up Mechanism Advice Letter annually, requesting modifications to the charges. The modifications are expected to return the projected principal balance of each outstanding class of certificates to the amount stipulated by the amortization schedule within a 12-month period. Any modifications to the charges will take into account any amount in the reserve sub-accounts available for distribution and any amounts necessary to fund the overcollateralization account and bring other accounts up to the required capital level. (See "Section IV. A Case Study: California" for further details on credit enhancements.)

Average-Life Variability

In the case of California, the weighted-average life of the certificates may be affected by the rate, timing and receipt of tariff collections, as well as the amounts available in the various equity, overcollateralization and reserve accounts. While accelerated receipts of the tariff charge will not be applied to pay down principal faster than the scheduled final distribution date, in limited circumstances, the certificates could in fact be retired later than expected. Should the charges in any given period prove insufficient to fund the debt service, interest is paid, but all or a portion of principal may be deferred into the next period. This may impact marginally the average life of the security. The presence of prompt true-up mechanisms will prevent any significant average-life drift from original projections.

A final word on true-ups is that they can be controversial from the perspective of state regulators as there is the potential for rate increases should the tariff cash flow be insufficient to maintain the expected amortization schedule. Alternatively, the presence of a true-up and the average-life stability it implies are welcomed by investors. Going forward, we cannot rule out the possibility that future deals may not include a true-up mechanism, opting instead for less controversial and more traditional ABS credit enhancements. There are numerous ways to structure the tariff to achieve a triple-A rating. Of course, we would expect spreads on RRBs that do not include a true-up to be slightly wider than spreads on RRBs that do because of the average-life variability risk. As a practical matter, if one assumes a growing economy and electric usage, true-ups will probably lower the CTC and thereby benefit rate payers. For this reason, true-ups should be favored by regulators and legislators.

Servicing

As in any securitization, servicing is an important issue. The servicer's effectiveness in ensuring the receipt and proper application of the receivable payments necessary to pay down a securitization is critical. In stranded-cost securitizations, the transferrer of the assets (the IOU) is expected to be designated the servicer under a pooling and servicing agreement, although a third party also may be servicer. The pooling and servicing agreement governs the servicer's responsibilities, including administering the timely billing and collection of the CTC charges and proper reporting to investors.

Practically speaking, the IOU is in the best position to service the transaction, given its access to consumption and billing data and its greater leverage in bringing about payment from customers through the ability to terminate service in the event of non-payment. Servicing is arguably less of an investor concern in a stranded-cost securitization, given that the IOU is a regulated entity. However, provisions should be made for a backup servicer in the event that the initial servicer is unable or fails to perform as specified. Servicing fees should be sufficient to attract a backup servicer.

Also, there should be periodic examinations of the presence and/or extent of the commingling of funds. If an IOU servicer mixes the proceeds from the receivables with its general corporate funds for any period of time, the receivables could be deemed a part of the general bankruptcy estate of the servicer. While the rating of the IOU generally is not a consideration in determining the IOU's viability in servicing the transaction, the rating agencies will look at the IOU's rating to assess the risks presented by commingling and to determine the acceptable number of days that funds can be commingled. Not surprisingly, higher rated IOUs may commingle funds for longer periods of time than IOUs with lesser ratings.

The Impact of Alternative "Energy Service Providers"

A final servicing issue is the presence of alternative energy service providers or ESPs. ESPs that provide consolidated billing to retail customers for the amounts owed the ESP for electricity and the amounts owed the utilities for distribution and other charges, including the CTC, must pass through the applicable charges to the utility. In this process, the ESP, in effect, replaces the customer as the obligor with respect to the CTC. The servicer may mitigate credit risks relating to ESPs in the same manner it mitigates such risks with customers. Thus the credit quality of the ESP does come into question.

In the case of California, the CPUC determined that any ESP electing to perform consolidated billing must first establish its creditworthiness by either demonstrating that it has a credit rating of "Baa2" or higher from Moody's or "BBB" or higher from S&P, Fitch and Duff & Phelps or by submitting a credit application to the servicer for evaluation with final credit approval granted by the servicer or submitting to the servicer a deposit equal to twice the estimated maximum monthly amount owed to the servicer. In addition, the presence of the true-up mechanism and the overcollateralization, capital and reserve accounts are intended to mitigate any shortfalls created by the ESP's failure to remit payments.

After-Market Liquidity

Projections as to the ultimate size of this market vary between $50 billion and $150 billion. If the truth lies somewhere in the middle, Rate-Reduction Bonds are destined to become a very liquid sector of the ABS market. Larger deals will range between $3 and $5 billion, with smaller and intermediate deals coming in around $300 million to $700 million, respectively. Thus, not only will the overall sector prove liquid, but also individual deals.

Alternatively, the fact that the sector has a finite amount of issuance in that once a utility recovers the appropriate amount of stranded assets, there is no further possibility of securitization, will ultimately cause liquidity to deteriorate over time. More likely is the prospect that this type of debt financing will replace in part the mortgage bond financings currently used in this industry.

Utility Legal, Tax and Accounting Issues

Bankruptcy Remote

Existing regulatory authority or supplemental legislation typically provides that the sale of the property right by the utility to a bankruptcy remote SPV or other financing entity be treated as a "true sale." It is not a pledge or other financing, provided that specific requirements are satisfied. Without the true-sale designation, the transaction could be viewed as a general collateralized borrowing. *It is this feature of the transaction that permits the Rate-Reduction Bonds to be assigned a credit rating above that of the utility.*

Such a regulatory ruling or legislation supported by nationally recognized, unqualified, independent counsel opinions explicitly removes a key investor concern, which is mainly the potential that, in the event of the IOU's bankruptcy, the CTC could be included in the bankruptcy estate of the utility. Given that the bonds are issued through a bankruptcy remote vehicle, the continued collection of debt service for the securitized bonds in the event of an IOU bankruptcy is highly likely. Should a regulatory ruling and/or legislation not address the true-sale issue, true-sale treatment under existing law, as in all other ABS transactions, would have to be established by the issuer and supported by a legal opinion from outside nationally recognized counsel.

Accounting/Tax Treatment

Ideally, IOUs would want securitizations to be treated as off-balance-sheet obligations for accounting purposes and on-balance-sheet debt for tax purposes. Off-balance sheet accounting treatment would prevent the IOU's debt portion of the balance sheet from ballooning. In addition, off-balance-sheet accounting would prevent confusion between securitized and non-securitized debt.

In the case of the California securitizations, the Securities & Exchange Commission (SEC) ruled that the securitizations for each IOU would not qualify for off-balance-sheet accounting treatment. The SEC concluded that the recovery of stranded costs did not qualify as a contractual right as defined by FASB 125 and that the proceeds received from the securitization must be reported as either debt or deferred revenue. Accordingly, the recoverable stranded costs did not qualify as a financial asset, precluding the utilities from accounting for the transaction as a sale of a financial asset for financial statement purposes. The rule in question when determining whether IOUs will be granted off-balance-sheet treatment is the Financial Account Standard Board's (FASB) Statement 125, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities." It remains to be seen how securitization transactions in other states will be determined. The rating agencies have indicated, however, that they will pro forma out the CTC bonds in their own analyses.

IOUs are requesting private letter rulings from the IRS to obtain debt treatment for tax purposes as opposed to true sale treatment. California IOUs received favorable private letter rulings allowing debt treatment for Federal tax purposes. While other utilities will have to make individual requests, the hope is that the IRS ruling will become standard for other utilities. Had the IRS found "true sale" treatment, the IOUs would have faced an immediate tax liability relating to the income recognized from the transaction, greatly reducing the financial feasibility of securitization. The utilities will be required to pay the same taxes on the CTC revenue as would have been required without securitization.

Relative Value To Other Fixed-Income Sectors

The first rate-reduction bond in 1997 was issued the week of November 24. The $2.9 billion California Infrastructure and Economic Development Bank SPT PG&E-1 (Pacific Gas & Electric) was extremely well received, as were the two subsequent California deals via Southern California Edison and San Diego Gas & Electric. The strong reception bodes well for this new asset class in 1998 and beyond.

Rate-Reduction Bonds are expected to continue to be well received by the institutional investing public. They should prove attractive not only to traditional ABS investors, but also to the more traditional corporate utility investor.

Traditional ABS investors, such as insurance companies, pension funds, banks and other money managers, will be attracted to the sector as it will allow them to diversify their portfolios away from consumer-debt related ABS, a key factor given continued concerns regarding delinquencies and charge-offs on consumer debt. As for the more traditional corporate utility buyer, issuance of utility first mortgage bonds has fallen substantially recently given the fact that construction has greatly decreased and is now funded largely through internal sources. Thus, even though the utility bonds will fall under the ABS flag, these traditional corporate buyers are expected to be large sponsors of this new asset class, given their need to diversify their risk over a number of corporate sectors. Those deals that include floating-rate tranches should be well received by European investors and those domestic investors who can take advantage of current wide swap spreads by accessing the swap market.

Versus Credit-Card ABS. The expected level principal payments on Rate-Reduction Bonds are similar to the payments on controlled-amortization credit cards, although they are currently trading closer to the levels found on bullet cards. From a credit perspective, stranded asset cash flows are of higher credit quality than credit cards since they are far less subject to delinquencies and charge-offs. For example, net charge-offs for San Diego Gas & Electric have held at or below 30 basis points since 1992; this compares extremely well with charge-offs on credit cards. The charge-off rate for Moody's Credit-Card Index as of September 1997 was 669 basis points. And, Rate-Reduction Bonds are not subject to early amortization as are credit cards.

Exhibit 6: Relative Value of Stranded-Cost Securitizations Versus Competing Fixed-Income Spreads

Spreads Closely Track Credit-Card Sector

	Maturity/Avg. Life (Yrs.)				
Sector	2	3	5	7	10
Rate-Reduction	38	39	43	48	51
Bullet Credit Cards	36	38	42	48	59
Tranched Autos	37	43	—	—	—
"A" Utility Bonds	35	39	47	51	64
"A" Industrial Bonds	33	37	40	48	55

Source. PSI's IMPACT data base and trading base. Data as of 3/3/98.

While it was believed initially that Rate-Reduction Bonds would price around five basis points wider than bullet cards, in fact, the last California issue priced even to cards in the shorter tranches and through the spreads on the intermediate and longer dated average-life classes. The tighter spreads on Rate-Reduction Bonds at the time of issuance caused the entire bullet ABS sector to tighten as well. Note from Exhibit 6 that Rate-Reduction Bonds are now trading just slightly wider or even to short and intermediate-term bullet fixed-rate card, but well through the levels on ten-year bullet cards.

Versus Auto-Loan ABS. Rate-Reduction Bonds most resemble tranched auto-loan ABSs due to their amortizing nature. On a spread basis, auto loans trade as much as four basis points wide to Rate-Reduction Bonds. This is not unexpected given that, just as in the credit-card sector, the collateral backing Rate-Reduction Bonds is far less susceptible to delinquency and charge-offs.

Versus Utility First Mortgage Bonds. Rate-Reduction Bonds are sharply more attractive than utility bonds on a spread basis in the front end of the curve, but trade even to much tighter in the five- to ten-year sectors. The new asset class is a good alternative for first mortgage bond investors, given the lack of net new supply in the utility sector (see Exhibit 7). The absence of first mortgage bond issuance is attributable to a handful of factors, including: (i) there is little need to build generation capacity given the excess capacity extent in the marketplace already (ii) the proceeds from securitization are likely to be directed in part to buying back mortgage debt and (iii) utilities with major investments in generation facilities will attempt to accelerate depreciation and the regulators may require that large portions of the depreciation be used to retire mortgage debt.

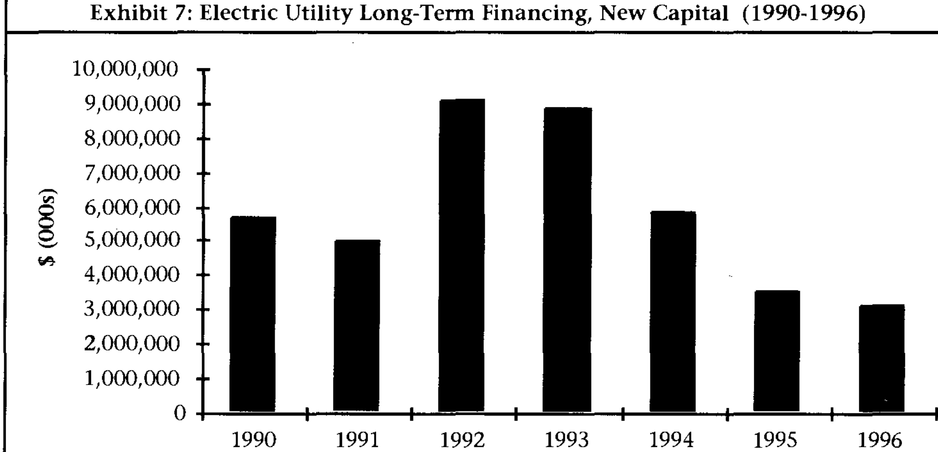
Effect of Securitization on the Utility's Outstanding First Mortgage Bonds

On balance, we expect a modestly positive impact on existing utility mortgage bonds as securitizations take place. Factors we have considered in making this judgment are as follows:

• **Addresses the Stranded-Cost Problem, Reduces Risk.** Securitizations will generally be seen as part of the process of resolving the problems of the utilities that undertake them, leaving them recapitalized and stronger. For example, securitization could help convert a utility facing possible risk due to inability to recover its stranded costs in a deregulated environment into a distribution utility (a lower risk business) or a vertically integrated utility with a competitive cost structure. This means the securitization would be considered neutral to positive depending on how the utility was perceived before the securitization.

• **Securitization Proceeds Used To Call or Tender for Mortgage Bonds.** At least part of the proceeds of most securitizations will likely be used to retire mortgage bonds and thus will add to their value by contributing to their scarcity and possibly causing them to trade ahead of their normal value to investors because the utility may have a bid for them which is higher than what an investor would pay.

Exhibit 7: Electric Utility Long-Term Financing, New Capital (1990-1996)



Source. Statistical Yearbook of the Electric Utility Industry, 1996.

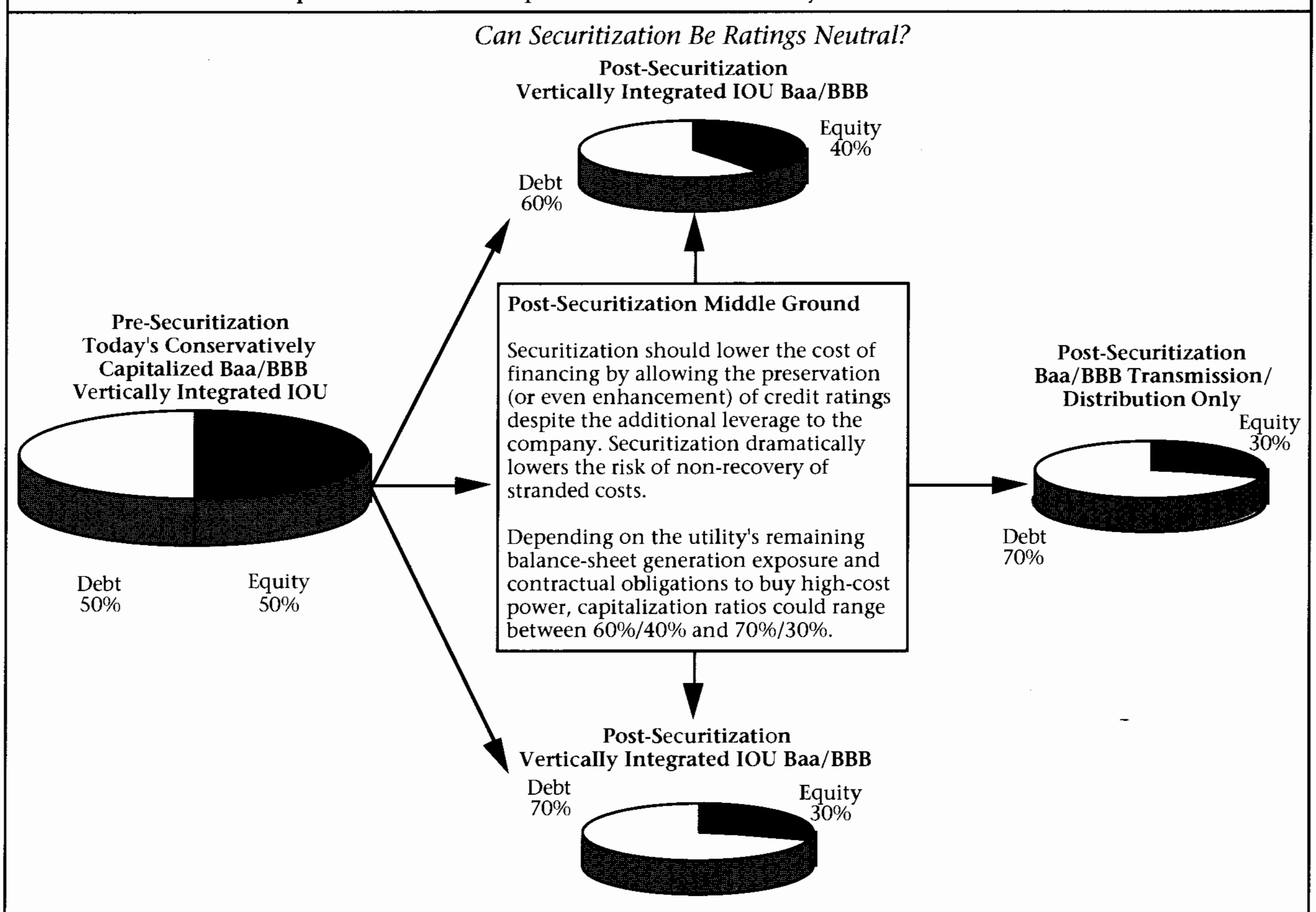
While we would not expect to see a negative effect on any utility's mortgage bonds in the near term from any of the securitizations currently under discussion, a valid argument can be made that securitization effectively deprives mortgage bondholders of their current senior position versus other creditors. This is the case because securitized bonds (such as those sold by Puget Power and the California electrics) have a first claim on a portion of the revenues from customers. Only those moneys left over after the necessary funds have been diverted to service the securitized bonds can be used to service the utility's own debt. Should a currently unforeseen problem strike at some future point, mortgage bondholders would presumably be in a weaker position, at that time, if there are securitized revenue bonds outstanding than would have been the case without them. We would agree that this state of affairs could be a concern down the road, but doubt if it will result in securitization ever appearing to actually weaken a utility at the time the securitization is first implemented. Alternatively, resolution of the stranded-cost issues should serve to reduce the risk facing electric utilities, which, in turn, is expected to be a positive factor for utility investors.

The Impact on an IOU's Recapitalized Balance Sheet

The final impact on the utility's credit quality will depend on how the utility has applied the proceeds from the securitization to recapitalize its balance sheet. Ratings could be negatively impacted if the utility buys back too much equity, unduly leveraging up its balance sheet. This issue will be hotly debated as regulators will want more expensive equity retired to increase rate reductions and utilities will seek to protect their credit standings. While it generally will not concern RRB holders, it may determine the timing and pace of new issues, since use of proceeds is a key regulatory concern.

In Exhibit 8, we analyze a currently conservatively capitalized triple-B rated, vertically integrated IOU before and after securitization. Prior to securitization, the utility is capitalized by an even split of debt and equity. However, as noted above, in order to produce sufficient cost savings to utility consumers, the utility must buy back a larger percentage of more expensive equity than debt, which will cause it to "lever up" its balance sheet and possibly impair ratings. *However, the utility will argue*

Exhibit 8: Capitalization Ratios: Triple-B Investor-Owned Utility — Pre- and Post-Securitization



that while the increased leverage does add more financial risk to the balance sheet than a given rating agency may normally tolerate, the reduction in overall business risk that stranded-cost recovery brings offsets the incremental financial risk.

For example, the agencies, as a rule of thumb, normally require a 60/40 debt-to-equity ratio for a utility to receive a triple-B rating. However, post-securitization, a utility that opts to remain vertically integrated may be allowed to increase its proportion of debt and still maintain its triple-B rating. This would be especially true if the utility in question had little remaining balance-sheet exposure in generation and/or no contractual obligations to buy high-cost power. In this case, a utility's capitalization ratio could likely fall somewhere between 60/40 and 70/30 and maintain its investment-grade rating. Furthermore, if the utility opted to become solely a transmission and distribution company and thus remained a regulated entity, it's possible that a 70/30 debt-to-equity ratio would be tolerated.

VI. A CASE STUDY: CALIFORNIA

The California restructuring plan has progressed much further than that of any other state at this point. For this reason (as well as the existence of $6.0 billion of "rate reduction bonds" sold in the closing days of 1997), we have included a review of the history of the restructuring process in California as well as many of the specifics of the California program as it now stands. We do not, however, consider California to be a "template" for other states because each will have its own particular political, legal and economic needs and obstacles.

One of the key lessons to be drawn from the California restructuring process is how much time it has taken from the initial CPUC statements in 1994 until the availability of customer choice on January 1, 1998. In fact, because of computer problems, the power exchange due to commence operation on January 1, 1998 has now been delayed until March.

While the experience gained in California will doubtless allow restructuring to progress at a faster pace elsewhere, we think each state will have to go through a detailed legal, political and regulatory process to reach a solid consensus on the specifics of restructuring.

There are two key reasons that California progressed from the signing of restructuring legislation in August 1996 to the sale of RRBs 15 months later. The first was the existence by the time the legislation was enacted of very complete agreements about the nature and amount of nuclear-related stranded costs judged eligible for recovery. The second was that prices under most of the utilities' independent power-purchase contracts were due to come down in the late 1990s. In the case of the power-purchase contracts, the utilities used some of the resulting cost reductions to help amortize stranded costs in the upfront years of the transition plan while still lowering residential and small commercial customers' rates 10%.

Pennsylvania did not have either of these two positives, so it is probably not surprising that it is lagging far behind California even though its legislation was enacted only three months later.

California has been in the forefront of the movement to restructure the electric utility industry ever since the CPUC's Division of Strategic Planning filed the infamous "Blue Book" in April 1994. The Blue Book was, in essence, a manifesto regarding the need for competition in generation. The hope was that it would lead to more cost-effective decisions than the recently completed wave of nuclear construction, as well as contracts signed by the utilities to buy power from independent generators. The CPUC accepted the concept that distribution and transmission facilities were probably natural monopolies (at least as far as smaller customers are concerned), but believed that the competitive provision of generation would save money for all electric customers.

By 1994, the CPUC had lost all fear regarding the adequacy of the state's power supply and was determined to bring costs down. Factors that contributed to the development of this viewpoint in California were:

- The state's stagnant economy,

- The recent wave of rate increases for the IOUs (occasioned by the completion of the Diablo Canyon, Palo Verde and San Onofre nuclear plants, as well as the commencement of expensive purchased power contracts);

- A general attitude of rebellion against some of the high costs of living and doing business in the state,

- The abundance of low priced natural gas, which made possible the construction of low cost, clean new generating capacity and

- The movement toward a competitive market for electric generation in the U.K.

Other factors on people's minds undoubtedly included the recent success of the CPUC in forcing Pacific Gas & Electric to re-negotiate higher priced contracts to purchase natural gas from Canada, FERC's success with Order 636 (which forced the unbundling of the natural gas transmission industry) and the evolving state of competition in the telephone industry, along with the success of performance based rate making plans in bringing down the real cost of most telephone service.

Initially, the CPUC seemed to lack an appreciation of the complexity of reaching the competitive environment they sought. They planned to introduce competition for the largest customers in January 1996 and phase it in gradually for everyone else. Large customers (long angry over electric rates higher than in most areas of the country, other than the Northeast) were all in favor of this approach. The commissioners seemed not to recognize the full importance of the stranded-cost issue and, like commissions elsewhere around the country, implied that they believed the utilities should threaten to stop honoring their contractual commitment to IPPs.

By 1995 they had caught on, however, and realized they would need to reach agreements with the three main utilities in the state regarding what those stranded costs were and how they were to be recovered. The utilities, too, were gaining a better understanding of the tenor of the times. By September 1995, Southern California Edison had signed a "Memorandum of Understanding" with the California Manufacturer's Association, the California Large Energy Consumers Association and the Independent Energy Producers. Also in that year, settlements were reached regarding the price Pacific Gas & Electric was to be paid for power from the Diablo Canyon nuclear unit and the procedure for Southern California Edison and San Diego Gas & Electric recovering their sunk costs relating to the San Onofre and Palo Verde nuclear plants. The latter was further "tweaked" in early 1996. To get these agreements, the utilities had to accept a lower allowed return on the equity investment in the plants. They also agreed to sell all of their fossil generating stations in order to:

• Promote competitive generation and

• Establish the fair market value of the facilities so it could be properly taken into account in calculating stranded costs.

Further on this point, the utilities agreed to share any residual value in the nuclear plants with rate payers after they had been fully written off during the transition period. This was California's way of dealing with the thorny problem of how to estimate what generating costs will be stranded in the future when the free-market price of power may be very different than it is today. Lastly, the CPUC acknowledged the need for full recovery of the costs associated with IPP contracts — a concession that has been made in many states in which such contracts account for a large amount of stranded costs.

By December 1995, the CPUC was ready to issue a policy decision with specific provisions, including (i) ensuring that all customer classes benefited from restructuring, (ii) creating a wholesale power pool (the so-called "power exchange" or "PX") into which all power suppliers would offer power and which would effectively determine the market clearing price on an hourly basis (all supplies also come out of the PX), (iii) transferring operational control (but not ownership) of the transmission facilities owned by the IOUs in the state to an "independent system operator" or "ISO" in order to ensure impartial operation of the system, (iv) full recovery by utilities of above-market stranded costs (in some cases with a reduced return on equity — (note nuclear sunk cost recovery plans in Exhibit 9) and (v) the eventual replacement of traditional cost-of-service regulation of distribution with non-cost based performance rate making.

By the summer of 1996, the stage was set for an all encompassing plan for the introduction of competition. As the summer wore on, the legislature, the utilities and many other interested parties came to see legislation as a good route to the resolution of the many remaining contentious issues surrounding the introduction of competition. Part of the reason matters moved on to the legislature, in our opinion, was the inability of the CPUC over the previous year to successfully broker a compromise agreeable to all key interested parties.

As debate raged in the legislature, each interest group pushed its own agenda:

• Large industrial customers wanted choice as soon as politically possible, with as short a stranded-cost recovery period as possible.

Exhibit 9: California's Nuclear Plant Cost-Recovery Settlements

Plant	Utility	Investment ($BB)	Cost Recovery: Sunk Cost	Cost Recovery: Current (ICIP)
San Onofre (Mgd. by So. Cal. Ed)	Southern Cal Ed.	2.7	To be recovered over 8 yrs. from 1/96	3.8 cts./kwh escalating to 4.15 cts. in 2002/2003
	San Diego G&E	0.75	Cost of capital on the unrecovered book value: *debt – actual embedded equity – 90% of debt cost*	same as above
Palo Verde 1,2 & 3 (Mgd. by AZ Pub. Svc.)	Southern Cal Ed.	1.2	To be recovered over 5 yrs from 1/97 with a 7.53% cost of capital on the unrecovered book value	Actual costs with reasonableness review
Diablo Canyon (Mgd. by Pacific G&E)	Pacific Gas & Electric*	4.4	To be recovered over 5 yrs. beg. from 1/1/97. Cost of capital on unrecovered book value: *debt – actual embedded equity – 90% of PG&E's actual embedded cost of debt or 6.77%*	3.3 cts./kwh escalating to 3.49 cts. in 2001

Source. PSI Fixed-Income Credit Research. *Plan revised by CPUC order effective 5/21/97.

• Politicians wanted to take credit for reducing rates for smaller customers (as well as for introducing choice for those customers who wanted it).

• Utilities wanted the security of having a definite (and feasible) plan in place for the recovery of their stranded costs. They lobbied for securitization because it would provide recovery of a large part of their stranded costs upfront so that such recovery could not later be denied them. The concept was sold to politicians as the way the utilities would be able to afford the January 1, 1998 10% rate reduction for smaller customers.

The legislation was passed on August 31, 1996 and later signed into law by Governor Wilson. Some of its specific provisions are as follows:

• Much of the stranded cost must be collected by March, 31, 2002. However, there are a number of exceptions, such as costs related to employee realignments, which may be collected through March 31, 2006, costs related to above-market purchased power contracts, which may be collected over the duration of the original contracts, and nuclear decommissioning.

• Nearly all electric sales are subject to payment of a CTC regardless of who supplies the power (but some self-generation and co-generation loads are exempt).

• CTCs will be collected through early March 2002 (or later allowable date) or completion of the recovery of the CTC.

• Rates will be frozen for industrial, agricultural and large commercial customers until the first wave of CTC recovery is complete or until March 31, 2002, whichever is earlier.

• A rate reduction of 10% will take effect on January 1, 1998 for residential and small-commercial customers. Rates will be frozen at this level through March 31, 2002.

• Rates for small customers are expected to drop again in 2002 when much of the transition cost recovery has been completed.

• Subject to obtaining financing orders from the CPUC, the utilities could be authorized to sell up to $10 billion in securitized revenue bonds.

• State funding of renewable generation will be instituted.

• Rates are to be unbundled to separately reflect the cost of energy transmission, distribution, recovery of CTC and the cost of social programs (low-income assistance, energy conservation, etc.).

Throughout 1997, proceedings were conducted at the CPUC dealing with the myriad of issues requiring resolution prior to the January 1, 1998 date for the switch over to the new system. Some key issues and their resolution were as follows:

— **Fossil Plant Divestitures.** All three utilities have decided to divest all their fossil generation, which will allow funds from this source to be credited against current stranded-cost recovery requirements.

— **Retail Choice.** All customers were to have had choice beginning January 1, 1998, but logistical problems have delayed this to March 31, 1998.

— **Components of the Revenue Requirement for Each of the Three Utilities.** The total price/kWh was frozen by the legislation, but significant fluctuation will occur in several components of the total charge to customers. The Fixed Transition Amount (FTA) will be "trued up" at least annually so as to ensure proper servicing of the securitized revenue bonds. The PX price will always reflect the current wholesale price of power. Several components of the cost structure have been determined by the CPUC on the basis of projected costs as was previously the case (transmission, distribution and public benefits). The remaining CTC amount will always be calculated by subtracting the FTA, PX price, transmission, distribution and public benefit costs from the frozen price/kWh. The utilities are at risk if the CTC (as calculated in this fashion) collected by the March 31, 2002 deadline for recovery of many categories of stranded cost is insufficient. Exhibit 10 provides a price breakdown per kWh for an average PG&E rate payer.

California Rate-Reduction Bonds

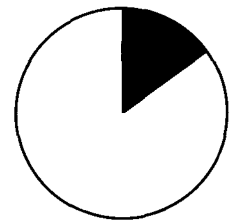
As noted earlier, three of California's largest IOUs, Pacific Gas & Electric, San Diego Gas & Electric and Southern California Edison, brought a combined $6.0 billion in stranded-cost securitizations late in 1997. The RRBs were extremely well received by the fixed-income capital markets. Exhibit 11 provides a brief description of the issue and classes on each of the California deals.

Rate-Reduction Bonds: How They Work in California

In the case of California, the California Infrastructure and Economic Development Bank (IEDB) authorized the creation of financing entities to issue and sell Rate-Reduction Bonds. These special-purpose entities are known as the "California Infrastructure and Economic Development Bank Special Purpose Trust (GE-1, SCE-1,

Exhibit 10: Pacific Gas & Electric 1998 Price Breakdown/KwH for Average Rate Payer

Price Component	Method of Determination	Amount (Cents)	Amount (% of Total Bill)
FTA	Amount per KwH that is necessary to service RRBs. Trued up at least annually so as to always be the correct amount.	1.5	15
PX Price	Price of power on CA power exchange (Fluctuates constantly, but assumed to be 2.5 cents for purposes of this illustration).	2.5	25
Transmission	Determined initially based on cost of service.	0.4	4
Other Distribution	Determined initially based on cost of service.	2.7	27
Public Benefits	Covers miscellaneous items such as low-income assistance.	0.4	4
Remaining CTC	The difference between the frozen total price of 9.9 cents and the sum of all the above components. (Will fluctuate constantly as the PX price fluctuates, but is assumed to be 2.4 cts. for purposes of illustration.)	2.4	24
Total Price/KwH		**9.9 cents**	**100%***



Source. Pacific Gas & Electric, California Public Utility Commission.
*Total does not sum to 100% due to rounding.

Exhibit 11: Structure and Pricing Levels on the California Rate-Reduction Bonds

Issue	Issue Size	Structure								
IEDB SPT PG&E-1	$2.9BB	Tranche	A-1	A-2	A-3	A-4	A-5	A-6	A-7	A-8
		Type	Float	Float	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed
		Tranche Size ($MM)	125	265	280	300	290	375	875	400
		Avg. Life (Yrs.)	0.56	1.09	2	3.02	4.02	5.17	7.31	9.48
		Spread (BPs.)	LIBOR+5	LIBOR+5	48	48	48	48	60	63
IEDB SPT SCE-1	$2.466BB	Tranche	A-1	A-2	A-3	A-4	A-5	A-6	A-7	
		Type	Float	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	
		Tranche Size ($MM)	247	308	248	246	361	741	315	
		Avg. Life (Yrs.)	0.79	1.79	2.93	3.93	5.17	7.4	9.54	
		Spread (BPs.)	LIBOR+4	45	45	45	54	58	59	
IEDB SPT SDG&E-1	$657.7MM	Tranche	A-1	A-2	A-3	A-4	A-5	A-6	A-7	
		Type	Float	Fixed	Fixed	Fixed	Fixed	Fixed	Fixed	
		Tranche Size ($MM)	65.8	82.6	66.2	65.6	96.5	197.5	83.5	
		Avg. Life (Yrs.)	0.77	1.77	1.77	3.92	5.17	7.39	9.52	
		Spread (BPs.)	LIBOR+4	41	41	43	49	54	56	

Source. MCMCorporateWatch.

PGE-1)." Each utility sold the transition property, which is the right to receive the non-bypassable FTA payments, to this trust in exchange for the proceeds of the sale of the Rate-Reduction Bonds. The transfer of the assets, in counsel's opinion, constituted a "true sale," which would prevent the assets from becoming part of any bankruptcy of the selling utilities. The "true sale" status is granted because the utilities' control of the assets is limited to servicing and collections. The sale transfers the risk of recovering the FTA from the IOU to the trust; however, the risk is considered to be slight given that utility customers are mandated by state legislation to pay the FTA. The collections by each utility as servicer will be allowed to be commingled with aggregate utility funds for brief periods.

The California deals were each multi-class, sequential-pay, fixed- and floating-rate amortizing structures. Principal of the RRBs will be amortized in equal amounts (level-pay amortization) rather than on a mortgage basis so that residential and small commercial rates may be reduced each year after the end of the rate freeze as the principal is amortized. The trusts will make quarterly payments of trustee fees, servicer fees, operating expenses, interest, principal and deposits to the various credit-enhancement accounts. Credit enhancement on the deals was provided via a number of sub-accounts and a true-up mechanism. A financing order allows the issuer of the securities to recover FTA charges for the creation of the overcollateralization account. The overcollateralization account is intended to enhance the likelihood that payments on the underlying notes are made in accordance with the expected amortization schedule. The overcollateralization amount was set to be 0.50% of the initial principal amount of the bonds or 50 basis points, but was to be collected "ratably" over the life of the securities. In addition, credit enhancement is provided by a 50-basis-point equity sub-account contributed by the seller at the close of the transaction and a reserve sub-account, which is created from FTA payments in excess of scheduled principal and interest payments on the bonds, expenses and allocations to the overcollateralization sub-account. Any balance in the reserve sub-account at the end of the year will be incorporated into the true-up adjustment. When necessary, the trust will draw from the sub-accounts in the following order: reserve, overcollateralization and capital.

The key form of credit enhancement comes via the true-up mechanism. The FTA amount is subject to an annual true-up to generate projected revenues sufficient to:

- Amortize the bonds and pay interest according to the expected amortization schedules,

- Fund the overcollateralization account,

- Pay the appropriate fees and expenses related to the servicing of the bonds and

- Replenish the capital sub-account to the extent that funds are drawn from the account.

The servicing agreement requires the servicer to seek and the CPUC to approve periodic adjustments to the FTA charges based on actual FTA collections, updated assumptions as to future electricity usage and expenses and the rate of delinquencies and write-offs. The servicer is required to file a routine True-Up Mechanism Advice Letter annually, requesting modifications to the FTA charges that will return the projected principal balance of each outstanding bond to the amount stipulated by the expected amortization schedule within a 12-month period, or, if earlier, the stated final maturity date. The servicer also may file a routine True-Up Mechanism Advice letter as often as quarterly. The true-up requests must take into account amounts available in the general sub-account and reserve sub-account as well as the amounts necessary to replenish the overcollateralization sub-account and equity sub-account to required levels.

VII. GLOSSARY

Aggregators. Brokers who seek to bring together customers or generators to buy or sell power in bulk, making a profit on the sale.

Amortization Compression. The increase in monthly payments as a result of shortening the amortization period, which reduces the immediate/upfront effect of savings created by the reduced cost of financing.

Avoided Cost. The cost the utility would incur to produce or otherwise procure electric power, but does not incur because the utility purchases this power from other producers.

Competitive Transition Charge (CTC). See "Special Tariff."

Customer Choice. The ability of electric consumers to choose among various providers for electric generation and other services.

Direct Access. Ability of customer to purchase commodity electricity directly from the wholesale market rather than through a local distribution utility.

Disaggregation. The functional separation of the vertically integrated utility into smaller, individually owned business units (i.e., generation, dispatch/control, transmission, distribution).

Electric Distribution. The delivery of electric energy to consumers connected to the electric power distribution system.

Electric Power Generation. The conversion of other forms of energy into electric energy. Bulk electric energy is generated from such energy sources as fossil fuels, nuclear fuel, geothermal steam, falling water, and alternative renewable energy resources.

Electric Transmission. The transportation of bulk quantities of electric energy by means of electric conductors from generation sources to an electric distribution system, a load center or an interface with a neighboring control area.

Federal Energy Regulatory Commission (FERC). The Federal executive agency responsible for regulating the activities of key portions of the nation's natural gas distribution utilities, electric utilities, natural gas pipeline transportation utilities and hydroelectric power producers. FERC is the Federal counterpart to state utility regulatory commissions.

FERC Order No. 888. Issued in April 1996, the order requires transmission owners under FERC's jurisdiction to open their transmission lines to all market participants under the same tariffs, terms and conditions enjoyed by the transmission owners themselves and allows wholesale buyers to seek competitive bids without economic impediment. It is believed to be the major catalyst for competition in the wholesale market.

Fixed-Transition Amount (FTA). See "Special Tariff."

Generation. The production of electricity at power plants. Electricity is generated by burning fossil fuel, burnup of nuclear fuel or from water power (hydroelectricity) or other alternative renewable energy sources.

Grid. A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points.

Independent Power Producer (IPP). A non-utility power generating entity that is not a qualifying facility. Independent power producers typically sell power they generate to electric utilities at wholesale prices, and the utility then resells this power to end-user customers.

Intangible Transition Charge. See "Special Tariff."

Investor Owned Utilities (IOUs). Regulated public utilities. Although they may be owned by shareholders, by a single proprietor or by a small group of individuals, this classification most commonly refers to utilities owned by large numbers of shareholders and organized as profit-making corporations.

Kilowatt. A watt is a unit of power in the International System of Units (SI) that is required to do work at the rate of 1 joule per second. Kilo is from the metric system and means 1,000. Thus a kilowatt is one-thousand watts or a kilowatt is power required to do work at the rate of 1000 joules per second. Utilities measure the size or capacity of a generating station in kilowatts.

Kilowatt Hour (kWh). Amount of electricity produced by a one kilowatt generator in one hour.

Load. The electric power used by devices or customers connected to an electrical generating system.

National Energy Policy Act of 1992 (EP ACT). Addresses a wide variety of energy issues. The legislation created a new class of power generators, exempt wholesale generators (EWGs). This new class of power generators is exempt from the provisions of the Public Utilities Holding Company Act of 1935. The EP Act also grants the FERC authority to order and condition access by eligible parties to the interconnected transmission grid.

Non-Utility Generators (NUGs). Facilities for generating electricity that are not owned exclusively by an electric utility (less than 50%) and which operate connected to an electric utility system. Included are qualifying co-generation facilities under PURPA and independent power producers.

Power Exchange (PX). Established by California's electric deregulation legislation and regulated by the FERC, the PX is a competitive, wholesale power pool into which all power suppliers would offer power and which would effectively determine the market clearing price on an hourly basis (all supplies also come out of the PX). Much like a stock exchange, the PX is where electricity will be bought and sold.

Public Utility Commission / Public Service Corporation Commission (PUC/PSCC). The state agency that regulates the rates and services of a variety of service providers, such as natural gas, telephone and electric utilities.

Public Utility Regulatory Policy Act of 1978 (PURPA). PURPA encouraged co-generation and small power production by requiring electric utilities to buy electric energy at avoided cost from facilities that met certain criteria (qualifying facilities or QFs).

Qualifying Facility (QF). A new category of electric generator defined by the Public Utility Regulatory Policy Act of 1978. Key characteristics that entitle a facility to QF status include the use of a renewable energy source or provision of steam to an industrial facility.

Rate Base. An IOU's net investment in facilities, equipment and other property a utility has constructed or purchased to provide utility service to its customers.

Rate-Reduction Bond (RRB). Any bond, debenture, note, interim certificate, trust certificate or other indebtedness that is secured by or payable from the collection of stranded-cost special tariffs, the savings of which are passed along to consumers.

Regulatory Compact. An implicit agreement that, in return for accepting the obligation to provide for the needs of its customers, a utility would be permitted to recover the prudently incurred cost of doing so, including earning a fair return on its investment.

Retail Market and Retail Wheeling. Retail describes the sale of power to an end-user of electricity such as industrial, commercial and residential customers. Retail wheeling is the process of moving electric power from a point of generation across one or more utility-owned transmission and distribution systems to a retail customer.

Revenue Requirement. The total amount of money a utility must collect from customers to pay all operating and capital costs, including a fair return on investment.

Special Purpose Vehicle / Special Purpose Entity (SPV/SPE). A bankruptcy remote entity to which an investor-owned utility transfers or sells the right to CTC cash flows.

Special Tariff. Synonymous with competitive transition charge and fixed-transition amount, a special tariff is levied against present and future electric power consumers. The tariff provides for the recovery of stranded costs and facilitates the move toward a deregulated electric industry. The special tariff is non-bypassable, meaning that applicable consumers cannot avoid paying the tariff if they choose, when deregulation occurs, to purchase electricity from a supplier other than the initial IOU.

Stranded Assets/Costs. The generation related assets and obligations that may become uneconomic as a result of a competitive deregulated electric utility generation market. Stranded costs arise mostly from uneconomic generating plants (generally nuclear), above market purchased power contracts with non-utility generators, state and local tax burdens and the recovery of deferred costs (regulatory assets).

True Sale. In the context of stranded-cost securitizations, a true sale is the transfer of transition property (property right) and not a secured borrowing.

True-Up Mechanism. In the case of stranded-cost securitizations, the utility will periodically adjust ("true-up") the special tariff to assure that projected tariff revenues will be sufficient to correct any variance in principal amortization from the expected level and restore any underfunded credit-enhancement balances by the end of the year. The true-up adjustment will be calculated based on revised revenue forecasts.

Unbundling. The separating of the total process of electric power service from generation to metering into its component parts for the purpose of separate pricing or service offerings.

Vertical Integration. In terms of the electric industry, it refers to the historically common arrangement whereby a utility owns its own generating plants, transmission system and distribution lines to provide all aspects of electric service.

Weighted Average Cost of Capital (WACC). The weighted average of the utility's cost of capital: the cost of common stock equity, preferred stock equity and long-term debt. The WACC is derived by adopting the capital structure, which specifies the relative amounts of equity and long-term debt that should constitute the company's long-term financing. Then the average estimated cost of capital is set for each component and the percentage amount of each component, or capitalization ratio, is multiplied by its estimated cost. Finally, the weighted figures are summed, resulting in the total weighted average cost of capital.

Wheeling Service. A service provided by an entity, such as a utility, that owns transmission facilities whereby it receives electric energy into its system from one party and then uses its facilities to deliver energy to a third party. The wheeling entity is paid a fee for this service.

Wholesale Market and Wholesale Wheeling. Wholesale sales are mostly sales from one utility to another or from an IPP to a utility. Wholesale wheeling is the process of moving bulk power from a generator across one or more utility-owned transmission systems to another utility for resale.

ENDNOTES

1. *Industry Outlook — Electric Utilities*, Moody's Investors Service.

2. "Electricity Prices in a Competitive Environment, Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities, A Preliminary Analysis Through 2015, August 1997," United States Department of Energy, Energy Information Administration, August 1997).

3. Ibid., pages 61 and 80).

4. Charles B. Curtis, Deputy Secretary U.S. Department of Energy.

5. "Federal Legislation To Deregulate Utilities, Washington Is Plugged Into The Electricity Debate -- But Not Hot Wired For Fast Action,`` Susan Lynmner, Barry M. Abramson and Carol M. Coale, Prudential Securities Inc., April 21, 1997.

Appendix A: Puget Power Conservation Transaction	
Issuer (6/95) Seller Service	Puget Power Conservation Grantor Trust Puget Sound Power & Light Co.
Amount	$202 million
Credit Rating	AAA/Aa2
Structure	Grantor trust, fixed-rate pass-through certificates
Coupon	6.45%
Average Life	3.8 years
Yield	55 basis points over the four-year Treasury
Expected Final Maturity	9.0 years
Collateral	Right to collect compensation from customers for approved and qualified conservation expenditures
Legislation	Washington State statute established rules permitting utilities to issue "conservation bonds" to finance new or existing conservation expenditures approved by the WUTC. Statute made the reimbursement rights of the holders of the conservation bonds irrevocable while bonds are outstanding and defined rules for the transfer, assignment and pledge of interests in the regulatory assets. The WUTC will revise the tariff if amounts collected vary by more than 2% from the amount needed to amortize the conservation credits on schedule.
Enhancement	True-up mechanism and increasing overcollateralization (initially 12 basis points).

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